March 2009

Regulatory Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Proposed Rule (GHG Reporting)

Final Report

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INTRODUCTION AND BACKGROUND

1.1 Background

On December 26, 2007, President Bush signed the FY2008 Consolidated Appropriations Amendment, which authorized funding for the U.S. Environmental Protection Agency (EPA) to develop and publish a draft rule on an accelerated schedule:

> [N]ot less than $3,500,000 shall be provided for activities to develop and publish a draft rule not later than 9 months after the date of enactment of this Act, and a final rule not later than 18 months after the date of enactment of this Act, to require mandatory reporting of GHG emissions above appropriate threshold in all sectors of the economy.

The accompanying explanatory statement stated that EPA shall "use its existing authority under the Clean Air Act" to develop a mandatory GHG reporting rule.

> The agency is further directed to include in its rule reporting of emission resulting from upstream production and downstream sources, to the extent that the Administrator deems it appropriate. The Administrator shall determine appropriate thresholds of emissions above which reporting is required, and how frequently reports shall be submitted to EPA. The Administrator shall have discretion to use existing reporting requirements for electric generating units under Section 821 of the Clean Air Act.

EPA is considering different options for the design of the reporting rule, including options that have different thresholds above which sources must measure and report their GHG emissions. The estimated costs and benefits for some alternatives are likely to exceed $100 million. Hence, a regulatory impact analysis (RIA) must be developed.

1.2 Role of the Regulatory Impact Analysis in the Rulemaking Process

1.2.1 Legislative Roles

This report analyzes the estimated regulatory impacts of the mandatory reporting program that EPA has developed, in accordance with the FY08 Appropriations language, under the authority of Sections 114 and 208 of the Clean Air Act [CAA]. Section 114 provides EPA broad authority to collect data for the purpose of "carrying out any provision" of the Act (except for a provision of Title II with respect to manufacturers of new motor vehicles or new motor vehicle engines). Section 114(a)[1] of the CAA authorizes the Administrator to, *inter alia,* require certain persons (see below) on a one-time, periodic or continuous basis to keep records, make reports, undertake monitoring, sample emissions, or provide such other information as the Administrator may reasonably require. This information may be required of any person who (i) owns or operates an emission source, (ii) manufactures control or process equipment, (iii) the Administrator believes may have information necessary for the purposes set forth in this section, or (iv) is subject to any requirement of the Act (except for manufacturers subject to certain title II requirements). The information may be required for the purposes of developing an implementation plan, an emission standard under sections 111, 112 or 129, determining if any person is in violation of any standard or requirement of an implementation plan or emissions standard, or "carrying out any provision" of the Act (except for a provision of title II with respect to manufacturers of new motor vehicles or new motor vehicle engines).[2] Section 208 of the CAA provides EPA with similar broad authority regarding the manufacturers of new motor vehicles or new motor vehicle engines, and other persons subject to the requirements of parts A and C of title II.

The scope of the persons potentially subject to a section 114(a)(1) information request (e.g., a person "who the Administrator believes may have information necessary for the purposes set forth in" section 114(a)) and the reach of the phrase "carrying out any provision" of the Act are quite broad. EPA's authority to request information reaches to a source not subject to the CAA, and may be used for purposes relevant to *any* provision of the Act. Thus, for example, utilizing sections 114 and 208, EPA could gather information relevant to carrying out provisions involving research (e.g., section 103(g)); evaluating and setting standards (e.g., section 111); and endangerment determinations contained in specific provisions of the Act (e.g., 202); as well as other programs.

While the Agency has published (July 11, 2008) an advanced notice of proposed rulemaking to explore the broader policy implications of regulating GHGs under the CAA, the Agency believes that establishing a mandatory reporting program for facilities emitting GHGs or supplying fuel and chemicals that will eventually be emitted as GHGs is necessary in order to inform and analyze future climate policy. This rule intends to provide a comprehensive data that cover a broad range of sectors in the economy, thereby establishing a solid foundation on which informed future climate decisions may be made.

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[1]The joint explanatory statement refers to "Section 821 of the Clean Air Act" but section 821 was part of the 1990 CAA Amendments and was not codified into the CAA itself.

[2]Although there are exclusions in section 114(a)(1) regarding certain title II requirements applicable to manufacturers of new motor vehicle and motor vehicle engines, section 208 authorizes the gathering of information related to those areas.

The Agency considered a wide range of determining factors when selecting the recommended alternative for this rule. These included the consideration of costs and benefits, which are essential to making efficient, cost-effective decisions for implementation of these standards. Other important considerations included the language of the Appropriations Act and the accompanying explanatory statement related to source categories; consistency with other CAA or state-level regulatory programs that typically require facility or unit level data and; the relative accuracy of different monitoring approaches and the monitoring methods already in use within the regulated industries; and the potential burden placed on small businesses associated with a range of reporting thresholds.

This RIA is intended to inform the public about the selection criteria for this rule, which include, but are not limited to, the potential costs and benefits that may result when the mandatory reporting program is implemented.

1.2.2 Role of Statutory and Executive Orders

There are several statutes and executive orders that dictate the manner in which EPA considers rulemaking and that apply to any public documentation. The analysis required by these statutes and executive orders is presented in Section 6.

EPA presents this RIA pursuant to Executive Order 12866 and the guidelines of Office of Management and Budget (OMB) Circular A-4 and EPA's Economic Guidelines.[3] These documents present guidelines for EPA to assess the benefits and costs of the selected regulatory option, as well as options that are more stringent or less stringent. The costs of the proposed mandatory reporting program are described in Section 4 of this RIA; the economic impact analysis and cost-effectiveness analysis of the program are presented in Section 4. The benefits of the proposed rule are discussed in Section 5.

1.2.3 Market Failure or Other Social Purpose

OMB Circular A-4 indicates that one of the reasons a regulation such as the proposed rule may be issued is to address market failure. The major categories of market failure include inadequate or asymmetric information, externalities, and market power. The proposed mandatory GHG reporting rule seeks to address inadequate or asymmetric information between and among GHG emitters and various other stakeholders including the public.

[3] U.S. Office of Management and Budget. Circular A-4, September 17, 2003: http://www.whitehouse.gov/omb/circulars/a004/a-4.pdf.

While some sectors of the U.S. economy report emissions of GHGs, and there are other sources of information about GHG emissions, the proposed rule would provide comprehensive data on emissions from sources throughout the economy. There currently is significant variation in which sectors of the U.S. economy report GHG emissions and methods used for calculations. As a result, existing information is inadequate or various stakeholders have very different information on which to base decisions about GHG emission levels and possible reductions.

An externality occurs when one party's actions impose uncompensated benefits or costs on another party. Environmental problems are a classic case of externality. Although not its primary focus of the proposed rule, the GHG reporting program will provide information on for future climate policies designed to address externalities. Since GHGs are an externality, the lack of information on their emissions means the information asymmetry leads to an inefficient outcome, and providing such information is a necessary step to internalize the externality.

1.2.4 Illustrative Nature of the Analysis

This analysis is illustrative of the types of costs and benefits that may accrue as a result of the program. The estimates of costs reflect existing production levels in each affected sector, and estimates of emissions are based on 2006 data. When the reporting program takes effect, actual patterns of economic activity and emissions may differ from current conditions. However, these data provide estimates of baseline conditions and estimated costs of compliance.

1.3 Overview and Design of the RIA

This RIA comprises seven sections. Following this introductory section, Section 2 describes affected sectors of the economy and reviews existing reporting programs. Section 3 describes the development of the proposed rule, including control options and analyses of alternative scenarios. Section 4 characterizes baseline conditions and presents engineering estimates of the costs of complying with the proposed rule. Section 5 presents an assessment of the monitoring and reporting costs by sector, an examination of uncertainty related to measurement accuracy of monitoring methods prescribed, and an assessment of potential impacts on small entities. Section 6 presents a qualitative examination of potential benefits of the proposed rule. Section 7 provides a discussion of the Agency's compliance with executive orders and other statutes during the development of the proposed rule. Section 8 describes EPA's conclusions and findings.

1.3.1 Baseline and Years of Analysis

Data used for the analysis represent the most recent data available on estimates of GHG emission by sector, productive capacity, existing emissions monitoring, and reporting activities by sector. While EPA recognizes that economic growth and changes in the structure of the economy over time will likely result in changes in both emissions and costs by sector, attempting to project these changes would lead to an increased level of uncertainty without conveying comparable improvements in the assessment. Thus, EPA uses data representing essentially current conditions as a proxy for conditions present when the rule takes effect. Such estimates are inherently uncertain because data needed for more precise measurements are not available. The data collected by the rule would greatly enhance future estimates.

1.3.2 Developing the Proposed GHG Reporting Rule Considered in this RIA

In order to ensure a comprehensive consideration of GHG emissions, EPA organized the development of the proposed rule around seven categories of processes that emit GHGs: (1) fossil fuel combustion: stationary, (2) fossil fuel combustion: mobile, (3) fuel suppliers, (4) industrial processes, (5) industrial GHG suppliers, (6) fossil fuel fugitive emissions, and (7) biological processes. For each category, EPA evaluated the requirements of existing GHG reporting programs, obtained input from stakeholders, analyzed reporting options, and developed the general reporting requirements and specific requirements for each of the GHG emitting processes.

EPA examined existing GHG reporting programs prior to developing the proposed rule. Although the mandatory GHG rule is unique, EPA carefully considered other federal and state programs during development of the proposed rule. One of EPA's goal was to develop a reporting rule that, to the extent possible and appropriate, is consistent with existing GHG emission estimation and reporting methodologies in order to reduce the burden of reporting for all parties involved. We document our review of GHG monitoring protocols for each source category used by federal, state, regional, and international voluntary and mandatory GHG programs, and our review of state mandatory GHG rules. The proposed monitoring and GHG calculation methodologies for many source categories are the same as, or similar to, the methodologies contained in state reporting programs.

EPA's overall rulemaking approach began with identification of anthropogenic sources in the U.S. GHG Inventory and International Panel on Climate Change (IPCC). The proposed rule would require reporting of CO_2, CH_4, N_2O, HFCs, PFCs, SF_6, and other fluorinated compounds (e.g., NF_3 and HFEs) as defined in the rule. The . The IPCC focuses on CO_2, CH_4, N_2O, HFCs, perfluorocarbons (PFCs), and SF_6 for both scientific assessments and emissions inventory purposes because these are long-lived, well-mixed GHGs not controlled by the Montreal Protocol on Substances that Deplete the Ozone Layer. These GHGs are directly emitted by human activities, are reported annually in EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks, and are the common focus of the climate change research community. The IPCC also included methods for accounting for emissions from several specified fluorinated gases in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.[4] These gases include fluorinated ethers, which are used in electronics and anesthetics and as heat transfer fluids. Like the other six GHGs that must be reported, these fluorinated compounds are long-lived in the atmosphere and have high global warming potentials (GWPs). In many cases these fluorinated gases are used in expanding industries (e.g., electronics) or as substitutes for HFCs. As such, EPA is proposing to include reporting of these gases to ensure that the Agency has an accurate understanding of the emissions and uses of these gases, particularly as those uses expand.

EPA then conducted a review of existing methodologies and reporting programs (e.g., California Air Resources Board [CARB], The Climate Registry [TCR], 1605b of the Energy Policy Act). EPA's review of existing reporting programs and measurement methodologies employed by existing federal and state programs is described in Section II of the Preamble to the Proposed Rule. EPA used this information to inform its selection of measurement and reporting methods for this rulemaking.

Once EPA had a complete list of source categories relevant to the U.S., the Agency systematically reviewed those source categories against the following criteria to develop the list to the source categories included in the proposal:

(1) include source categories that emit the most significant amounts of GHG emissions, while also minimizing the number of reporters, and

(2) include source categories that can be measured with an appropriate level of accuracy. Source categories that would be required to report were identified. Sources were then screened by several key criteria, looking at the number of reporters versus the coverage of emissions under various thresholds, relevant and appropriate measurement methodologies, measurement accuracy, and administrative burden. Based on the source level screening activities, possible reporting methodologies for the selected sources were developed. The reporting methodologies identified fall into several categories including, direct measurement, calculating emissions based on site-specific information, and calculating emissions based on default emissions factors. In general, for the proposed rule, EPA selected a combination of direct emission measurement and calculations based on site-specific information.

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[4]The 2006 IPCC Guidelines are found here: http://www.ipcc.ch/ipccreports/methodology-reports.htm. For additional information on these gases please see Table A-1 in proposed 40 CFR part 98, subpart A and the Industrial GHG Suppliers Technical Support Document (EPA-HQ-OAR-2008-0508-141).

Once the source categories and methodologies had been identified, EPA evaluated different rule options across the following dimensions:

- Threshold (level of emissions below which entities are not required to report);
  - 1,000 tons CO_2e/year;
  - 10,000 tons CO_2e/year;
  - 25,000 tons CO_2e/year;
  - 100,000 tons CO_2e/year;
  - Equivalent capacity based threshold where data exists;
- Methodology for measuring emissions;
  - Direct measurement;
  - Facility specific calculation methods;
  - Default emissions factors;
- Frequency of reporting: Annually, quarterly, or some other frequency;
- Verification responsibility: EPA, third party, or self-certification without independent verification?

The Agency examined several options for each dimension to identify the preferred or recommended option. The options and alternatives evaluated are described in detail in Section 3. Section 4 details the engineering cost analysis which outlines the monitoring and reporting activities and costs for each source required to report.

1.3.3 Evaluating Costs and Benefits

To assist in the selection of the recommended option EPA conducted an economic impact analysis across the above dimensions. EPA estimated the costs of complying with each of the reporting alternatives, and assessed the cost-effectiveness of each alternative by examining the costs per million metric ton of CO_2 equivalent (MMtCO_2e) reported. This cost-effectiveness metric was considered in combination with other important factors such as the potential impacts on small entities, consistency with other CAA or state-level regulatory programs and monitoring methods already in use within the regulated industries.

1.4 Recommended Greenhouse Gas Reporting Alternative

The recommend option for this proposed rule is outlined below. Section 5 provides cost comparisons for each alternative evaluated under the following four dimensions. The recommended option strikes a balance between impacts on small entities, consistency with other programs, costs incurred by the reporting entities, and emissions coverage.

- **Threshold**: Hybrid approach
  - A facility that emits 25,000 metric tons CO_2e/year reports emissions from all sources for which there are methods or
  - An equivalent capacity threshold for source categories where data exist
  - An "all-in" threshold for source categories where analyses indicate that all facilities emit more than 25,000 metric tons CO_2e/year or that only a few facilities emit marginally below this level.
  - May select other thresholds where already reporting (e.g., Acid Rain Program [ARP]) or due to unique issues (e.g., GHG generation threshold for landfills)
  - Equivalent capacity threshold provided where data exist
- **Methodology**: Combination of direct measurement and source-specific calculation methodologies
  - Direct measurement of emissions from units at facilities that are already required to collect and report data using continuous emission monitoring systems under other Federally enforceable programs, including for other regulatory programs (e.g., CO_2 emissions from Electricity Generating Units [EGUs] in ARP; requirements of NSPS, NESHAP, SIP)
  - Source-specific calculation methods using facility-specific information for other sources at the facility
- **Frequency**: Annual
  - All reporters
  - Exception: those already reporting quarterly for existing mandatory programs (e.g., Acid Rain Program, Mine Safety and Health Administration, Energy Information Administration)
- **Verification**: Self-certification with EPA verification

1.5 References

U.S. Environmental Protection Agency. Advance Notice of Proposed Rulemaking: Regulating Greenhouse Gas Emissions Under the Clean Air Act. EPA-HQ-OAR-2008-0318, July 11 2008. http://www.epa.gov/climatechange/anpr.html.

U.S. Environmental Protection Agency. Preamble to the Proposed Mandatory Greenhouse Gas Reporting Rule; EPA-HQ-OAR-2008-0508-001.

U.S. Office of Management and Budget. Circular A-4, September 17, 2003. http://www.whitehouse.gov/omb/circulars/a004/a-4.pdf.

SECTION 2
REGULATORY BACKGROUND

The intent of this proposed rule is to collect accurate and timely GHG emissions data that can be used to inform future policies. Although the mandatory GHG rule is unique, EPA carefully considered other federal and state programs during development of the proposed rule. The reporting program will supplement rather than duplicate other U.S. government GHG programs. We outline EPA's overall rulemaking approach, sources considered, and summarize our review of GHG monitoring protocols for each source category used by federal, state, regional, and international voluntary and mandatory GHG programs, and our review of state mandatory GHG rules below. For example, the proposed monitoring and GHG calculation methodologies for many source categories are the same as, or similar to, the methodologies contained in state reporting programs. The remainder of the section provides an overview of related existing programs and discusses their relevance in the development of this rule.

2.1 EPA's Overall Rulemaking Approach

In response to the FY2008 Consolidated Appropriations Amendment, EPA has developed this proposed rulemaking. The components of this development are explained in the following subsections.

2.1.1 Identifying the Goals of the Greenhouse Gas Reporting System

The mandatory reporting program will provide comprehensive and accurate data which will inform future climate change policies. Potential future climate policies include research and development initiatives, economic incentives, new or expanded voluntary programs, adaptation strategies, emission standards, a carbon tax, or a cap-and-trade program. Because we do not know at this time the specific policies that will be adopted, the data reported through the mandatory reporting system should be of sufficient quality to support a range of approaches. Also, consistent with the Appropriations Amendment, the reporting rule proposes to cover a broad range of sectors of the economy.

To these ends, we identified the following goals of the mandatory reporting system:

- Obtain data that is of sufficient quality that it can be used to support a range of future climate change policies and regulations.
- Balance the rule coverage to maximize the amount of emissions reported while excluding small emitters.

- Create reporting requirements that are consistent with existing GHG reporting programs by using existing GHG emission estimation and reporting methodologies to reduce reporting burden, where feasible.

2.1.2 Developing the Proposed Rule

In order to ensure a comprehensive consideration of GHG emissions, EPA organized the development of the proposed rule around seven categories of processes that emit GHGs: (1) fossil fuel combustion: stationary, (2) fossil fuel combustion: mobile, (3) fuel suppliers, (4) industrial processes, (5) industrial GHG suppliers, (6) fossil fuel fugitive emissions, and (7) biological processes. For each category, EPA evaluated the requirements of existing GHG reporting programs, obtained input from stakeholders, analyzed reporting options, and developed the general reporting requirements and specific requirements for each of the GHG emitting processes.

2.1.3 Evaluation of Existing Greenhouse Gas Reporting Programs

A number of State and regional GHG reporting systems currently are in place or under development. EPA's goal is to develop a reporting rule that, to the extent possible and appropriate, would rely on similar protocols and formats of the existing programs and, therefore, reduce the burden of reporting for all parties involved. Therefore, each of the work groups performed a comprehensive review of existing voluntary and mandatory GHG reporting programs, as well as guidance documents for quantifying GHG emissions from specific sources. These GHG reporting programs and guidance documents included the following:

- International programs, including the IPCC, the EU Emissions Trading System, and the Environment Canada reporting rule;
- U.S. national programs, such as the U.S. GHG inventory, the ARP, DOE 1605(b) voluntary registry, and voluntary GHG partnership programs (e.g., Natural Gas STAR);
- State and regional GHG reporting programs, such as TCR, RGGI, and programs in California, New Mexico, and New Jersey;
- Reporting protocols developed by nongovernmental organizations, such as WRI/WBCSD; and
- Programs from industrial trade organizations, such as the American Petroleum Institute's Compendium of GHG Estimation Methodologies for the Oil and Gas Industry and the Cement Sustainability Initiative's CO_2 Accounting and Reporting Standard for the Cement Industry, developed by WBCSD.

In reviewing these programs, we analyzed the sectors covered, thresholds for reporting, approach to indirect emissions reporting, the monitoring or emission estimating methods used, the measures to assure the quality of the reported data, the point of monitoring, data input needs, and information required to be reported and/or retained. We analyzed these provisions for suitability to a mandatory, Federal GHG reporting program, and compiled the information. A summary of existing reporting programs examined is provided in Section 2.4. The full review of existing GHG reporting programs and guidance may be found in the docket at EPA-HQ-OAR-2008-0508-054.

2.1.4 Stakeholder Outreach to Identify Reporting Issues

Early in the development process, we conducted a proactive communications outreach program to inform the public about the rule development effort. We solicited input and maintained an open door policy for those interested in discussing the rulemaking. Since January 2008, EPA staff have held more than 100 meetings with stakeholders, including the following:

- trade associations and firms in potentially affected industries/sectors;
- state, local, and tribal environmental control agencies and regional air quality planning organizations;
- state and regional organizations already involved in GHG emissions reporting, such as TCR, CARB, and Western Climate Initiative (WCI); and
- environmental groups and other nongovernmental organizations.
- We also met with U.S. Department of Energy (DOE) and U.S. Department of Agriculture (USDA), which have programs relevant to GHG emissions.

During the meetings, we shared information about the statutory requirements and timetable for developing a rule. Stakeholders were encouraged to provide input on key issues. Examples of topics discussed included existing GHG monitoring and reporting programs and lessons learned, thresholds for reporting, schedules for reporting, scope of reporting, handling of confidential data, data verification, and the role of states in administering the program. As needed, the EPA technical workgroups followed up with these stakeholder groups on a variety of methodological, technical, and policy issues. EPA staff also provided information to tribes through conference calls with different Indian tribal working groups and organizations at EPA and through individual calls with tribal board members of TCR.

For a full list of organizations EPA met with when development this proposal please see the memo found at EPA-HQ-OAR-2008-0508-055.

2.1.5 Analysis of Emissions by Sector

For each of the source categories mentioned in Section 2.4, EPA compiled information on current conditions in the category, including information about existing monitoring equipment or reporting frameworks, estimated emissions of GHGs, and estimated productive capacity or throughput. Incremental costs of measuring GHG emissions and conducting reporting activities were estimated under each scenario. The scenarios vary the conditions of the reporting rule with respect to the size of the firm required to report, the frequency of reporting, who verifies emissions, and the type of measurement required by sector. The scenarios are listed in Section 3. EPA also reviewed the benefits to stakeholders, including the public, the government, and industry, of a reporting system in a qualitative analysis. These benefits are outlined in Section 5.

2.2 Sources Considered

Seven technical subgroups at EPA considered emissions sources from several broad categories, as shown in Table 2-1. Using screening criteria based on the feasibility of monitoring, verifying, and measuring these sources, the technical subgroups developed reporting methodologies for the sources in Table 2-2.

Table 2-1. Sources of GHG Emissions Considered

Source	GHG Emission Considered
Downstream	
Direct emitters	**Stationary combustion**: Sources that may be considered include stationary combustion units (e.g., EGUs, boilers, furnaces, turbines, kilns).
	Industrial processes: Emissions result from the physical or chemical transformation of materials in the mineral (e.g., cement, lime, glass), metal (e.g., iron, steel, ferroalloy, aluminum) and chemical (e.g., HCFC-22 production, nitric acid, petrochemical) industries.
	Fugitive emissions[1]: Intentional and unintentional emissions result from the extraction, processing, storage, and transport of fossil fuels (coal, oil, and gas) to the point of final use.
	Biological processes: Sources that may be considered include emissions from sources in the waste, agricultural, and forestry sectors (e.g., landfills, waste water treatment, and manure management operations).
Upstream	
Fuel suppliers	**Producers/refiners/importers**: Reporting from fuel providers and importers (e.g., petroleum refiners and importers, coal mines, gas processing plants, LNG importers).
Industrial gas suppliers	**Producers/importers**: Reporting from producers and importers from industrial gases (e.g., HFC, PFC, SF_6, CO_2, and N_2O).
Mobile Sources	
Mobile combustion	**Emissions from vehicles and engines in use:** Reporting from vehicle manufacturers and heavy duty and nonroad engine manufacturers. Sources include passenger cars, large/heavy duty truck cabs and chassis, light and medium duty trucks and vans, motorcycles, and other miscellaneous vehicles and engines.

1. This definition of fugitive emissions is derived from the definition of fugitives outlined in the 2006 Intergovernmental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories, and is consistent with the use of the term in the development of GHG inventories. In non-GHG related reporting efforts, fugitives are more narrowly defined to be emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Some source categories were excluded as a result of this screening step, such as emissions from land use changes and agricultural soils, fugitive emissions from selected oil and gas operations, and vehicle fleets. Vehicle fleet emissions are covered by reporting from fuel suppliers as part of the oil and gas production. Other emissions sources were excluded due to the large uncertainty associated with measuring, monitoring, and verifying the emissions. Further detail regarding the rationale for the exclusion of sources can be found in Section IV of the Preamble for this rule.

Table 2-2. GHG Source Categories Included in the Regulatory Analyses

Source Categories	
Electricity generators	Phosphoric acid production
Other large stationary combustion equipment (e.g., boilers, furnaces, engines)	Electronics
Mobile combustion (e.g., vehicle and heavy duty equipment manufacturers)	Iron and steel
Petroleum refineries	Aluminum production
Gas processors	Magnesium production
Coal mines	Ferroalloy production
Industrial gas suppliers/importers	Zinc production
LNG terminals	Lead production
Liquid/solid/gaseous fuel importers	Cement manufacturing
HCFC-22 production	Lime manufacturing
Ammonia manufacture	Limestone/dolomite-FGD
Nitric acid production	Limestone/dolomite-glass
SF_6 from electrical equipment	Silicon carbide production/consumption
Adipic acid production	Pulp & paper
Hydrogen production	Natural gas systems
Semiconductor	Petroleum systems
Petrochemical production	Landfills
Titanium dioxide	Manure management
Soda ash manufacture	Wastewater treatment

Consistent with the appropriations language regarding reporting of emissions from "downstream sources," EPA is proposing reporting requirements from facilities that directly emit GHGs above a certain threshold as a result of combustion of fuel or processes. The majority of the direct emitters included in this proposal are large facilities in the electricity generation or industrial sectors. In addition, many of the electricity generation facilities are already reporting their CO_2 emissions to EPA under existing regulations. As such, these facilities have only a minimal increase in the amount of data they have to provide EPA on their CH_4 and N_2O emissions. The typical industrial facilities that are required to report under this proposal have emissions that are substantially higher than the proposed thresholds and are already doing many of the measurements and quantifications of emissions required by this proposal through existing business practices, voluntary programs, or mandatory state-level GHG reporting programs.

For more information about the thresholds included in the proposal please refer to Section IV.C of the preamble and for more information about the requirements for specific sources refer to Section V of the preamble for the proposed rule.

Consistent with the appropriations language regarding reporting of emissions from "upstream production," EPA is proposing reporting requirements from upstream suppliers of fossil fuel and industrial GHGs. In the context of GHG reporting, "upstream emissions" refers to the GHG emissions potential of a quantity of industrial gas or fossil fuel supplied into the economy. For fossil fuels, the emissions potential is the amount of CO_2 that would be produced from complete combustion or oxidation of the carbon in the fuel. In many cases, the fossil fuels and industrial GHGs supplied by producers and importers are used and ultimately emitted by a large number of small sources, particularly in the commercial and residential sectors (e.g., HFCs emitted from home A/C units or GHG emissions from individual motor vehicles). To cover these direct emissions would require reporting by hundreds or thousands of small facilities. To avoid this impact, the proposed rule does not include all of those emitters, but instead requires reporting by the suppliers of industrial gases and suppliers of fossil fuels. Because the GHGs in these products are almost always fully emitted during use, reporting these supply data will provide an estimate of national emissions while substantially reducing the number of reporters. For this reason, the proposed rule requires reporting by suppliers of coal and coal-based products, petroleum products, natural gas and natural gas liquids (NGLs), CO_2 gas, and other industrial GHGs.

2.3 How the Proposed Mandatory GHG Reporting Program is Different from the Federal and State Programs EPA Reviewed

The various existing state and federal programs EPA reviewed are diverse. They apply to different industries, have different thresholds, require different pollutants and different types of emissions sources to be reported, rely on different monitoring protocols, and require different types of data to be reported, depending on the purposes of each program. None of the existing programs require nationwide, mandatory GHG reporting by facilities in a large number of sectors, so EPA's proposed mandatory GHG rule development effort is unique in this regard.

Although the mandatory GHG rule is unique, EPA carefully considered other Federal and State programs during development of the proposed rule. Documentation of our review of GHG monitoring protocols for each source category used by Federal, State, and international voluntary and mandatory GHG programs, and our review of State mandatory GHG rules can be found at EPA-HQ-OAR-2008-0508-056. The proposed monitoring and GHG calculation methodologies for many source categories are the same as, or similar to, the methodologies contained in State reporting programs such as TCR, CCAR, and State mandatory GHG reporting rules and similar to methodologies developed by EPA voluntary programs such as Climate Leaders. The reporting requirements set forth in 40 CFR part 75 are also being used for this proposed rule. Similarity in proposed methods will help maximize the ability of individual reporters to submit the emissions calculations to multiple programs, if desired. EPA also continues to work closely with states and state-based groups to ensure that the data management approach in this proposal will lead to efficient submission of data to multiple programs..

The intent of this proposed rule is to collect a reasonable estimate of GHG emissions data that can be used to inform future policy decisions. One goal in developing the rule is to be consistent with the GHG protocols and requirements of other state and federal programs, where appropriate, in order to make use of existing cooperative efforts and reduce the burden to facilities submitting reports to other programs. However, we also need to be sure the mandatory reporting rule collects facility-specific data of sufficient quality to achieve the Agency's objectives for this rule. The rule must require facilities to report all of the information EPA needs. Therefore, some reporting requirements of this proposed rule are different from other federal and state programs.

2.4 Existing Reporting Programs

A number of voluntary and mandatory GHG programs already exist or are being developed at the State, regional, and Federal levels. These programs have different scopes and purposes. Many focus on GHG emission reduction, whereas others are purely reporting programs. In addition to the GHG programs, other Federal emission reporting programs and emission inventories are relevant to the proposed GHG reporting rule. Several of these programs are summarized in this section.

In developing the proposed rule, we carefully reviewed the existing reporting programs, particularly with respect to emissions sources covered, thresholds, monitoring methods, frequency of reporting and verification. States may have, or intend to develop, reporting programs that are broader in scope or are more aggressive in implementation because those programs are either components of established reduction programs (e.g., cap and trade) or being used to design and inform specific complementary measures (e.g., energy efficiency). Where possible, we built upon concepts in existing Federal and State programs in developing the mandatory GHG reporting rule.

2.4.1 Inventory of U.S. Greenhouse Gas Emissions and Sinks

The U.S. greenhouse gas inventory, prepared by EPA's Office of Atmospheric Programs in coordination with the Office of Transportation and Air Quality, is an impartial, policy-neutral report that tracks annual GHG emissions. The annual report presents historical U.S. emissions of CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6.

The United States submits the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* to the Secretariat of the United Nations Framework Convention on Climate Change (UNFCCC) as an annual reporting requirement. The UNFCCC treaty, ratified by the United States in 1992, sets an overall framework for intergovernmental efforts to tackle the challenge posed by climate change. The United States has submitted the GHG inventory to the United Nations every year since 1993. The annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks* is consistent with national inventory data submitted by other UNFCCC parties, and uses internationally accepted methods for its emission estimates.

In preparing the annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, EPA leads an interagency team that includes the Department of Energy (DOE), USDA, the Department of Transportation (DOT), the Department of Defense (DOD), the State Department, and others. EPA collaborates with hundreds of experts representing more than a dozen federal agencies, academic institutions, industry associations, consultants, and environmental organizations. The *Inventory of U.S. Greenhouse Gas Emissions and Sinks* is peer-reviewed annually by domestic experts and by UNFCCC, and undergoes a 30-day public comment period, and is peer reviewed annually by UNFCCC review teams.

The *Inventory of U.S. Greenhouse Gas Emissions and Sinks* is a comprehensive, top-down national assessment of national greenhouse gas emissions, and uses top-down national energy data and other national statistics (e.g., on agriculture). To achieve the goal of comprehensive national emissions coverage for reporting under the UNFCCC, most GHG emissions in the report are calculated via activity data from national-level databases, statistics, and surveys. The use of the aggregated national data means that the national emissions estimates are not broken down at the geographic or facility level. In contrast, this reporting rule focuses on bottom-up data and individual sources above appropriate thresholds. Although it will provide more specific data, it will not provide full coverage of total annual U.S. GHG emissions, as is required in the development of the Inventory in reporting to the UNFCCC.

The mandatory GHG reporting rule will help to improve the development of future national inventories for particular source categories or sectors by advancing the understanding of emission processes and monitoring methodologies. Facility, unit, and process level GHG emissions data for industrial sources will improve the accuracy of the Inventory by confirming the national statistics and emission estimation methodologies used to develop the top-down inventory. The results can indicate shortcomings in the national statistics and identify where adjustments may be needed.

Therefore, although the data collected under this rule will not replace the system in place to produce the comprehensive annual national Inventory, it can serve as a useful tool to better improve the accuracy of future national-level inventories.

2.4.2 Federal Voluntary Greenhouse Gas Programs

EPA and other federal agencies operate a number of voluntary GHG reporting and reduction programs that EPA reviewed when developing this proposal, including Climate Leaders, several non-CO_2 voluntary programs, the Combined Heat and Power (CHP) partnership, the SmartWay Transport Partnership program, the National Environmental Performance Track Partnership, and the DOE 1605(b) voluntary GHG registry. Several other federal voluntary programs encourage emissions reductions, clean energy, or energy efficiency; this summary does not cover them all (for additional information see *Review of Existing Programs*, EPA-HQ-OAR-2008-0508-054). This summary focuses on programs that include voluntary GHG emission inventories or reporting of GHG emissions reduction activities for sectors that were considered for inclusion in this rulemaking.

2.4.2.1 Climate Leaders

Climate Leaders is an EPA partnership program that works with companies to develop GHG reduction strategies. Over 250 industry partners in a wide range of sectors have joined this program. Partner companies complete a corporate-wide inventory of GHG emissions and develop an inventory management plan using Climate Leaders protocols. Each company sets GHG reductions goals and submits to EPA an annual GHG emissions inventory documenting their progress. The annual reporting form provides corporate-wide emissions by type of emissions source.

2.4.2.2 Non-CO_2 Voluntary Partnership Programs

Since the 1990s, EPA has operated a number of non-CO_2 voluntary partnership programs aimed at reducing emissions from GHGs such as methane, SF_6, and PFCs. There are four sector-specific voluntary methane reduction programs: Natural Gas STAR, Landfill Methane Outreach Partnership (LMOP), Coalbed Methane Outreach Programs (CMOP), and Ag STAR. In addition, there are sector-specific voluntary emissions reduction partnerships for high global warming potential gases. The Natural Gas STAR partnership encourages companies across the natural gas and oil industries to adopt practices that reduce methane emissions. LMOP and CMOP encourage voluntary capture and use landfill and coal mine methane, respectively, to generate electricity or other useful energy. These partnerships focus on achieving methane reductions. Industry partners voluntarily provide technical information on projects they undertake to reduce methane emissions on an annual basis, but they do not submit methane emissions inventories. AgSTAR encourages beneficial use of agricultural methane from manure management systems but does not have partner reporting requirements.

There are two sector-specific partnerships to reduce SF_6 emissions: the SF_6 Emission Reduction Partnership for Electric Power Systems, with over 80 participating utilities, and the SF_6 Emission Reduction Partnership for the Magnesium Industry. Partners in these programs implement practices to reduce SF_6 emissions and prepare corporate-wide annual inventories of SF_6 emissions using protocols and reporting tools developed by EPA. There are also two partnerships focused on PFCs: The Voluntary Aluminum Industrial Partnership (VAIP) promotes technically feasible and cost-effective actions to reduce PFC emissions; industry partners track and report PFC emissions reductions. Similarly, the Semiconductor Industry Association and EPA formed a partnership to reduce PFC emissions in which a third party compiles data from participating semiconductor companies and submits an aggregate (not company-specific) annual PFC emissions report.

2.4.2.3 Combined Heat and Power Partnership

The Combined Heat and Power partnership is an EPA partnership that cuts across sectors. It encourages use of CHP technologies to generate electricity and heat from the same fuel source, thereby increasing energy efficiency and reducing GHG emissions from fuel combustion. Corporate and institutional partners provide data on existing and new CHP projects but do not submit emissions inventories.

2.4.2.4 SmartWay Transport Partnership

The SmartWay Transport Partnership program is a voluntary partnership between freight industry stakeholders and EPA to promote fuel efficiency improvements and GHG emissions reductions. Over 900 companies have joined including freight carriers (railroads and trucking fleets) and shipping companies. Carrier and shipping companies commit to measuring and improving the efficiency of their freight operations using EPA-developed tools that quantify the benefits of a number of fuel-saving strategies. Companies report progress annually. The GHG data that carrier companies report to EPA is discussed further in Section V.QQ.4b of the preamble.

2.4.2.5 National Environmental Performace Track Partnership

The Performance Track Partnership is a voluntary partnership that recognizes and rewards private and public facilities that demonstrate strong environmental performance beyond current requirements. Performance Track is designed to augment the existing regulatory system by creating incentives for facilities to achieve environmental results beyond those required by law. To qualify, applicants must have implemented an independently-assessed environmental management system, have a record of sustained compliance with environmental laws and regulations, commit to achieving measurable environmental results that go beyond compliance, and provide information to the local community on their environmental activities. Members are subject to the same legal requirements as other regulated facilities. In some cases, EPA and states have reduced routine reporting or given some flexibility to program members in how they meet regulatory requirements. This approach is recognized by more than 20 states that have adopted similar performance-based leadership programs.

2.4.2.6 1605(b) Voluntary Registry

The DOE EIA established a voluntary GHG registry under Section 1605(b) of the Energy Policy Act of 1992. The program was recently enhanced and a final rule containing general reporting guidelines was published on April 21, 2006 (71 FR 20784); the rule is contained in 10 CFR Part 300. Unlike EPA's proposal, which requires reporting of greenhouse emissions from facilities over a specific threshold, the DOE 1605(b) registry allows anyone (e.g., a public entity, private company, or an individual) to report their emissions and their emissions reduction projects to the registry. Large emitters (e.g., anyone that emits over 10,000 tons of CO_2e per year) who wish to register emissions reductions must submit annual company-wide GHG emissions inventories following technical guidelines published by DOE and must calculate and report net GHG emissions reductions. The program offers a range of reporting methodologies from stringent direct measurement to simplified calculations using default factors and allows the reporters to report using the methodological option they choose. In addition, as mentioned above, unlike EPA's proposal, sequestration and offset projects can also be reported under the 1605(b) program. There is additional flexibility offered to small sources who can choose to limit annual inventories and emissions reduction reports to a single type of activity rather than reporting company-wide GHG emissions, but must still follow the technical guidelines. Reported data are made available on the Internet in a public use database.

2.4.2.7 Summary

These voluntary programs are different in nature from the proposed mandatory GHG emissions reporting rule. Industry participation in the programs and reporting to the programs is entirely voluntary. A small number of sources report, compared to the number of facilities that will likely be affected by the proposed mandatory GHG reporting rule. Most of the EPA voluntary programs do not require reporting of annual emissions data, but are instead intended to encourage GHG reduction activities and track partner's successes in implementing such projects. For the programs that do include annual emissions reporting (e.g., Climate Leaders, DOE 1605[b]) the scope and level of detail are different. For example, Climate Leaders' annual reports are generally corporate-wide and do not contain the facility and process-level details that would be needed by a mandatory program to verify the accuracy of the emissions reports.

At the same time, aspects of the voluntary programs serve as useful starting points for the mandatory GHG reporting rules. Greenhouse gas emission calculation principles and protocols have been developed for various types of emission sources by Climate Leaders, the DOE 1605(b) program, and some partnerships such as the SF_6 reduction partnerships and SmartWay. Under these protocols, reporting companies monitor process or operating parameters to estimate greenhouse emissions, report annually, and retain records to document their GHG estimates. Through the voluntary programs, EPA, DOE, and participating companies have gained understanding of processes that emit GHGs and experience in developing and reviewing GHG emission inventories.

2.4.3 Federal Mandatory Reporting Programs

2.4.3.1 Acid Rain Program

The Acid Rain Program (ARP) and NO_x Budget Trading Program (NBP) are cap-and-trade programs designed to reduce emissions of SO_2 and NO_x[5]. As a part of those programs, facilities that serve a generator larger than 25 megawatts (MW) to report emissions. The 40 CFR

[5]For more information about these cap and trade programs see http://www.epa.gov/airmarkets/

Part 75 continuous emissions monitoring rule establishes monitoring and reporting requirements under these programs. The regulations in 40 CFR part 70 require continuous monitoring and quarterly and annual emissions reporting of CO_2 mass emissions, SO_2 mass emissions, NO_x emission rate, and heat input. Part 75 contains specifications for the types of monitoring systems that may be used to determine CO_2 emissions and sets forth operations, maintenance, and quality assurance/quality control (QA/QC) requirements for each system. In some cases, EGUs are allowed to use simplified procedures other than CEMS(e.g., monitoring fuel feed rates and conducting periodic sampling and analyses of fuel carbon content) to determine CO_2 emissions. Under the regulations, affected EGUs must submit detailed quarterly and annual CO_2 emissions reports using standardized electronic reporting formats. If CEMS are used, the quarterly reports include hourly CEMS data and other information used to calculate emissions (e.g., monitor downtime). If alternative monitoring programs are used, detailed data used to calculate CO_2 emissions must be reported.

The joint explanatory statement accompanying the FY2008 Consolidated Appropriations Amendment specified that EPA could use the existing reporting requirements for electric generating units under section 821 of the 1990 CAA Amendments. As described in Sections V.C. and V.D. of this preamble, because the part 75 regulations already require reporting of high quality CO_2 data from EGUs, the GHG reporting rule proposes to use the same CO_2 data rather than require additional reporting of CO_2 from EGUs. They will, however, have to include reporting of the other GHG emissions, such as CH_4 and N_2O, at their facilities.

2.4.3.2 Toxics Release Inventory

TRI requires facility-level reporting of annual mass emissions of approximately 650 toxic chemicals. If they are above established thresholds, facilities in a wide range of industries report including manufacturing industries, metal and coal mining, electric utilities, and other industrial sectors. Facilities must submit annual reports of total stack and fugitive emissions of the listed toxic chemicals using a standardized form which can be submitted electronically. No information is reported on the processes and emissions points included in the total emissions. The data reported to TRI are not directly useful for the GHG rule because TRI does not include GHG emissions and does not identify processes or emissions sources. However, the TRI program is similar to the proposed GHG reporting rule in that it requires direct emissions reporting from a large number of facilities (roughly 23,000) across all major industrial sectors. Therefore, EPA reviewed the TRI program for ideas regarding program structure and implementation.

2.4.3.3 Vehicle Reporting

EPA's existing criteria pollutant emissions certification regulations, as well as the fuel economy testing regulations which EPA administers as part of the CAFE program, require vehicle manufacturers to measure and report CO_2 for essentially all of their light duty vehicles. In addition, many engine manufacturers currently measure CO_2 as an integral part of calculating emissions of criteria pollutants, and some report CO_2 emissions to EPA in some form.

2.4.4 Other EPA Emissions Inventories

2.4.4.1 National Emissions Inventory

EPA compiles the National Emissions Inventory (NEI), a database of air emissions information provided primarily by state and local air agencies and tribes. The database contains information on stationary and mobile sources that emit criteria air pollutants and their precursors, as well as hazardous air pollutants. Stationary point source emissions that must be inventoried and reported are those that emit over a threshold amount of at least one criteria pollutant. Many states also inventory and report stationary sources that emit amounts below the thresholds for each pollutant. The point source NEI includes over 60,000 facilities. Required point source information consists of facility identification information; process information detailing the types of air pollution emission sources, air pollution emission estimates (including annual emissions), control devices in place, stack parameters, and location information. The NEI differs from the proposed GHG reporting rule in that the NEI contains no GHG data, and the data are reported primarily by State agencies rather than directly reported by industries . However, in developing the proposed rule, EPA used the NEI to help determine sources that might need to report under the GHG reporting rule. We considered the types of facility, process and activity data reported in NEI to support the emissions data as a possible model for the types of data to be reported under the GHG reporting rule. We also considered systems that could be used to link data reported under the GHG rule with data for the same facilities in the NEI.

2.4.5 State and Regional Voluntary Programs for Greenhouse Gas Emissions Reporting

A number of States have demonstrated leadership and developed corporate voluntary GHG reporting programs individually or joined with other States to develop GHG reporting programs as part of their approaches to addressing GHG emissions. This section of the preamble summarizes two prominent voluntary efforts. In developing the greenhouse rules, EPA reviewed the relevant protocols used by these programs as a starting point. We recognize that these programs may have additional monitoring and reporting requirements than those outlined in the proposed rule in order to provide distinct program benefits.

2.4.5.1 California Climate Action Registry

The California Climate Action Registry (CCAR) is a voluntary GHG registry already in use in California. CCAR has released several methodology documents, including a general reporting protocol, general certification (verification) protocol, and several sector-specific protocols. Companies submit emissions reports using a standardized electronic system. Emission reports may be aggregated at the company level or reported at the facility level.

2.4.5.2 The Climate Registry

The Climate Registry (TCR) is a partnership formed by U.S. and Mexican states, Canadian provinces, and tribes to develop standard GHG emissions measurement and verification protocols and reporting system capable of supporting mandatory or voluntary GHG emission reporting rules and policies for its member states. TCR has released a final General Reporting Protocol that contains procedures to measure and calculate GHG emissions from a wide range of source categories. They have also released a general verification protocol, and an electronic reporting system. Founding reporters (companies and other organizations that have agreed to voluntarily report their GHG emissions) implemented a pilot reporting program in 2008. Annual reports will be submitted covering six GHGs. Corporations must report facility-specific emissions broken out by type of emission source (e.g., stationary combustion, electricity use, direct process emissions) within the facility.

2.4.6 State and Regional Mandatory Programs for Greenhouse Gas Emissions Reporting and Control

Several individual States and regional groups of States have demonstrated leadership and are developing or have developed mandatory GHG reporting programs and GHG emissions control programs. This section of the preamble summarizes two regional cap-and-trade programs and several State mandatory reporting rules. We recognize that, like the current voluntary regional and State programs, State and regional mandatory reporting programs may evolve or develop to include additional monitoring and reporting requirements than those included in the proposed rule. In fact, these programs may be broader in scope or more aggressive in implementation because the programs are either components of established reduction programs (e.g., cap and trade) or being used to design and inform specific complementary measures (e.g., energy efficiency).

2.4.6.1 Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative (RGGI) is a regional cap-and-trade program that covers CO_2 emissions from EGUs larger than 25 MW in member states in the Mid-Atlantic and

Northeast. The program goal is to reduce CO_2 emissions to 10% below 1990 levels by the year 2020. RGGI will utilize the CO_2 reported to and QA/QCed by EPA under 40 CFR Part 75 to determine compliance of the EGUs in the cap-and-trade program. In addition, the EGUs in RGGI that are not currently reporting to EPA under the Acid Rain and NO_x Budget programs (e.g., co-generation facilities) will start reporting their CO_2 data to EPA for QA/QC, similar to the sources already reporting. Certain types of offset projects will be allowed, and GHG offset protocols have been developed. The states participating in RGGI have adopted state rules (based on a model rule) to implement RGGI in each state. The RGGI cap-and-trade program took effect on January 1, 2009.

2.4.6.2 Western Climate Initiative

WCI is another regional cap-and-trade program being developed by a group of Western States and Canadian provinces. The goal is to reduce GHG emissions to 15 percent below 2005 levels by the year 2020. Draft options papers and program scope papers were released in early 2008, public comments were reviewed, and final program design recommendations were made in September 2008. Other elements of the program, such as reporting requirements, market operations, and offset program development continues. Several source categories are being considered for inclusion in the cap and trade framework. The program might be phased in, starting with a few source categories and adding others over time. Points of regulation for some source categories, calculation methodologies, and other reporting program elements are under development. The WCI is also analyzing alternative or complementary policies other than cap-and-trade that could help reach GHG reduction goals. Options for rule implementation and for coordination with other rules and programs such as TCR are being investigated.

2.4.7 State Mandatory Greenhouse Gas Reporting Rules

Seventeen states have developed, or are developing, mandatory GHG reporting rules.[6] The docket for this rule contains a summary of these state mandatory rules (EPA-HQ-OAR-2008-0508-056). Final rules have not yet been developed by some of the states, so details of some programs are unknown. Reporting requirements have already effect in twelve states as of 2009; the rest will begin between 2010 and 2012. Reporting is typically annual, although some states require quarterly reporting for EGUs, consistent with RGGI and ARP.

State rules differ with regard to which facilities must report and which GHGs must be reported. Some states require all facilities that must obtain Title V permits to report GHG

[6]These are California, Colorado, Connecticut, Delaware, Hawaii, Iowa, Maine, Maryland, Massachusetts, New Jersey, New Mexico, North Carolina, Oregon, Virginia, Washington, West Virginia, and Wisconsin.

emissions. Others require reporting for particular sectors (e.g., large EGUs, cement plants, refineries). Some state rules apply to any facility with stationary combustion sources that emit a threshold level of CO_2. Some apply to any facility, or to facilities within listed industries, if their emissions exceed a specified threshold level of CO_2e. Many of the state rules apply to six GHGs covered by this proposed rule (CO_2, methane, nitrous oxide, HFCs, PFCs, SF_6); others apply only to CO_2 or a subset of the six gases. Most require reporting at the facility level, or by unit or process within a facility.

The level of specificity regarding GHG monitoring and calculation methods varies. Some of the states refer to use of protocols established by TCR or CCAR, to industry-specific protocols (such as methods developed by the American Petroleum Institute [API]), to accepted international methodologies such as IPCC, and/or to emission factors in EPA's *Compilation of Air Pollutant Emission Factors* (known as AP-42) or other EPA guidance.

2.1.7.1 California Mandatory Greenhouse Gas Reporting Rule

The mandatory reporting rule of the California Air Resources Board (CARB) is an example of a state rule that covers multiple source categories and contains relatively detailed requirements, similar to this proposal developed by EPA. According to the CARB proposed rule (originally proposed October 19, 2007, and revised on December 5, 2007), monitoring must begin on January 1, 2009, and the first reports will be submitted in 2010. The rule requires facility-level reporting of all GHGs (except PFCs) from cement manufacturing plants, electric power generation and retail markets, cogeneration plants, petroleum refineries, hydrogen plants, and facilities with stationary combustion sources emitting greater than 25,000 tons CO_2 per year. Part 75 (ARP) data will be used for EGUs. The CARB rule contains specific GHG estimation methods that are largely consistent with CCAR protocols, and also rely on API protocols and IPCC/European Union protocols for certain types of sources. California continues to participate in other national and regional efforts, such as TCR and WCI, to assist with developing consistent reporting tools and procedures on a national and regional basis.

SECTION 3
DEVELOPMENT OF THE PROPOSED MANDATORY REPORTING RULE

To develop the Mandatory GHG Reporting Rule, EPA considered various dimensions of the reporting program and developed and evaluated several options for each dimension. After a preliminary evaluation of the options for each dimension, a recommended reporting program alternative was selected. Several possible program alternatives were selected, generally by varying one dimension at a time, while retaining the recommended option for the other dimensions. These alternatives were then evaluated based on estimated cost, cost-effectiveness (cost per ton of emissions reported), and estimated impacts on small entities. This process is discussed in greater detail below.

3.1 Rule Dimensions for Which Options Were Identified

Possible designs for the Mandatory GHG Reporting Rule were developed by varying options across four dimensions:

1. **Thresholds:** In the language of the appropriations bill that calls for the development of the reporting rule, the EPA Administrator is called upon to identify “appropriate thresholds” above which facilities are required to report their GHG emissions. Thresholds may be based on production or productive capacity, or they may be based on emissions.
2. **Measurement Methodology:** To be able to report their GHG emissions, facilities will be required to measure them using an appropriate methodology. Generally, measurement methodologies may be based on instrumentation and direct measurement, or on calculation of measurements based on other data available to the facility (e.g., activity data and emissions factors).
3. **Reporting Frequency:** Reporting frequency may be annual, quarterly, or monthly.
4. **Verification:** For QA/QC purposes, a facility’s reported emissions of GHG could be verified, either by the Agency receiving the report (EPA, in this case), or by a third party, or reported emissions could be self-certified by the reporter without independent verification.

The options EPA considered for each dimension are discussed below and summarized in Table 3-1.

3.1.1 Thresholds

Three options were considered in setting the threshold above which reporting of GHG emissions will be required: capacity-based thresholds, emissions-based thresholds, or a hybrid of the two. Within each option, various definitions and levels of the threshold were examined.

Table 3-1. Options Considered in Developing Scenarios (Recommended Option Indicated by Shading)

Threshold	Methodology	Frequency	Verification
Capacity-based	Direct measurement (CEMS)	Quarterly for all	EPA verifies
Emissions based 1,000t CO_2e	Hybrid: Direct measurement for facilities already reporting and facility-specific calculations for others	Annual for all except quarterly for facilities already reporting quarterly	Third-party verifier
Emissions-based 10,000 tCO_2e	Default emissions factors from EPA		
Emissions-based 25,000 tCO_2e	Existing federal data used for measurement of fuel suppliers		
Emissions-based 100,000 tCO_2e			
Hybrid: 25,000 tCO_2e unless already reporting based on capacity under another program			
Only upstream sources report emissions			

Option 1: Capacity-based threshold

A capacity-based threshold would be defined based on the emitting facility's throughput, production, or productive capacity. In defining the capacity-based threshold, EPA considered that using a source-level capacity measure for the threshold might be a more straightforward way for facilities to know that they must report their GHG emissions, but the data on source-level capacity is not currently universally available to EPA.

Option 2: Emissions-based threshold

Option 2 involves the use of actual facility-level emissions of GHGs, measured in metric tons of CO_2-equivalent emissions (tCO_2e). Various levels were considered, ranging from 1,000 tCO_2e to 100,000 tCO_2e. Obviously, lower thresholds would require more sources to participate in the reporting program. The emissions threshold was analyzed for upstream producers as well. In those cases the analyses were done on the quantity of emissions that would occur when the fuel supplied was combusted or the chemicals supplied were used or released to the atmosphere at the end of life of the product. An emissions based threshold was not considered for manufacturers of motor vehicles and engines due to current reporting requirements that require manufacturers to report in terms of an emissions rate. Given current data availability, an emissions-based threshold will generally focus on larger, emissions-intensive industries for which emissions data are readily calculated or measured.

Option 3: Hybrid (recommended)

The hybrid threshold option is a combination of three general groups: capacity, emissions, or entire source category ("All in"). The thresholds developed are generally equivalent to a facility-wide threshold of 25,000 metric tons of CO_2e per year of actual emissions. The preference is to establish thresholds for as many source categories as possible based on a capacity metric, for example, tons of product produced per year. A capacity-based threshold is least burdensome, because a facility would not have to estimate emissions to determine if the rule applies. However, EPA faces two key challenges in trying to develop capacity thresholds. First, in most cases, data are insufficient to determine an appropriate capacity threshold. Secondly, for some source categories, defining the appropriate capacity metric is infeasible. For example, for some source categories, GHG emissions are not related to production capacity, but are more affected by design and operating factors.

3.1.2 Measurement Methodology

EPA identified three measurement methodology options, ranging from installing emissions monitoring equipment on all sources to using default emissions factors to estimate emissions. The measurement methodology options are discussed below.

All sources required to report under this rule will also be required to report electricity usage data. This will provide a better understanding of how electricity is used in the economy and the major industrial sectors. The rule would not provide for adjustments to take into account the purchases of renewable energy credits or other mechanisms. Monitoring of electricity use is accomplished through accounting of kilowatt hours billed for on utility statements.

Option 1: Direct measurement for all reporters

This option would apply direct measurement requirements to all reporters. This would require facilities to use continuous emissions monitoring systems in the stacks from stationary combustion units and industrial for solid fuel and processes emissions, continuous measurement of solid fuel use (or solid fuel production for upstream producers), and fuel flow meters for liquid and gaseous fuels and for upstream producers.

Option 2: Hybrid of direct measurement where already used and facility-specific calculation for other sources (recommended)

EPA's recommended measurement methodology option would require direct measurement of emissions from units at facilities that already are required to collect and report data using CEMS under other Federally enforceable programs (e.g., ARP, NSPS, NESHAP, SIPs). facilities to use direct measurement of emissions where facilities are already using CEMS (e.g., ARP) andFacilities with units that do not have CEMS installed could calculate emissions using facility-specific information and methods specified in the rule.

Option 3: Default emissions factor calculation for both combustion and process emissions

Under Option 3, EPA would require facilities to base their reported emissions on simplified calculations performed at the facility level, based on EPA-provided default factors combined with the type of fuel combusted, the type of process, production rate, and/or the quantity of fuel/chemical inputs used.

3.1.3 Reporting Frequency

EPA identified two options for reporting frequency: quarterly reports or annual reports. To minimize costs, EPA recommends annual reports, except for those facilities already reporting quarterly under another program.

Option 1: Quarterly

Under Option 1, all reporters would be required to submit their emissions data quarterly.

Option 2: Annually (recommended)

Under Option 2, EPA would require all reporters to submit their emissions data annually, except for those facilities already reporting data quarterly to the Energy Information Administration or for existing mandatory reporting programs, such as ARP or the Mine Safety and Health Administration (MSHA) program.

3.1.4 Verification

For QA/QC purposes, facility emissions reports could be verified by an outside entity, whether the government or a private third party. A third option is self-certification by the reporter without any independent verification.

Option 1: EPA as verifier (recommended)

Under this option, the reporter submits and self-certifies emissions data and other specified activity data directly to EPA., and EPA would review the emissions estimates and the supporting data contained in the reports, and perform other activities (e.g., comparison of data across similar facilities, site visits) to verify that the reported emissions data are accurate and completeperform the QA/QC checks using the submitted information. This is the approach used for verification under ARP and a number of other EPA and federal programs.

Option 2: Third-party verifier

Under this option, the reporter would self-certify their emissions data and also hire a private firm to verify their data and estimation methods prior to submitting the emissions data to EPA. The private firm would likely be required to be selected from a list of such firms that have been pre-certified by EPA. This third-party verification is similar to the approach used for the California mandatory reporting rule and the Climate Registry.

3.2 Recommended Options

As described above, EPA evaluated a variety of options for each dimension of the proposed GHG reporting program, and selected a preferred or recommended option for each dimension. Table 3-1 illustrates the options examined under each dimension, and shows the recommended option by shading. We summarize the recommended option for each dimension below.

- **Threshold**: Hybrid approach
  - A facility that emits 25,000 metric tons CO_2e/year or more reports all sources for which there are methods.
  - The thresholds fall generally into three groups: capacity, emissions, or entire source category ("All in"). The capacity and "all-in" thresholds are roughly equivalent to 25,000 metric tons CO_2e/year.
  - A facility may be subject to a capacity threshold when already reporting (e.g., ARP) or to another type of threshold due to unique issues or where an emissions-based threshold is not practical (e.g., GHG generation threshold for landfills).
- **Measurement Methodology**: Hybrid approach, with source-specific methodologies
  - A facility must use direct measurement of stationary combustion and some process sources where CEMS are currently installed and the facility is required to collect and report data using CEMS under other Federally enforceable programs (e.g., ARP, NSPS, NESHAP, SIPs).
  - A facility must use source-specific calculation methods contained in the rule and site-specific data to calculate emissions fromfor other sources at the facility.
- **Reporting Frequency**: Annual
  - All reporters would report their emissions annually.

- An exception exists for those already reporting quarterly for existing mandatory programs (e.g., ARP, MSHA, EIA).

§ **Verification**: Self-certification with EPA verification

- A facility would report emissions data and supporting information directly to EPA; EPA will use the information to verify the data.

3.3 Alternative Scenarios Evaluated

EPA developed alternative reporting scenarios and assessed the costs and emissions associated with each. Alternative scenarios were developed by creating the recommended scenario (the recommended option for each dimension, as shown in Table 3-1), then varying the levels in one dimension while keeping the other three dimensions at the recommended options. The alternative reporting scenarios evaluated are listed below:

1. A 1,000 tCO_2e threshold; recommended options for methodology, frequency, and verifier.
2. A 10,000 tCO_2e threshold; recommended options for methodology, frequency, and verifier.
3. A 100,000 tCO_2e threshold; recommended options for methodology, frequency, and verifier.
4. Direct techniques (CEMS, flow meters) are used to measure emissions; recommended option for threshold, frequency, and verifier.
5. Default emissions factors (simplified methods) are used to measure emissions; recommended option for threshold, frequency, and verifier.
6. Existing federal data used for measurement of fuel suppliers; recommended option for threshold, frequency, verifier, and methodology for other sources.
7. EPA uses default carbon content for fuel suppliers; recommended option for threshold, frequency, verifier, and methodology for other sources.
8. Reporting is quarterly; recommended option for threshold, methodology, and verifier.
9. Verification is done by a third party; recommended option for threshold, methodology, and frequency.
10. Only upstream sources report emissions; recommended option for methodology, frequency, and verifier.

The evaluation of the alternative reporting scenarios will allow policy makers to see the impact of each variation and assess their cost compared to the recommended option. Total costs, emissions, and cost-effectiveness of the alternative reporting scenarios are discussed in Section 4. Additionally, Section 5 provides a qualitative exploration of the effect on emissions coverage and total cost by moving to substantially lower thresholds such as 100 or 250 tCO_2e.

3.4 Data Quality for this Analysis

For this analysis, EPA gathered existing data from EPA, industry trade associations, states, and publicly available data sources (e.g., labor rates from the Bureau of Labor Statistics [BLS]) to characterize the processes, sources, sectors, facilities, and companies/entities affected. Costs were estimated based on the data collected and engineering analysis and models provided by EPA and its contractors. EPA staff and contractors provided engineering expertise, knowledge of existing facility conditions and activities (e.g., whether CO_2 or non-CO_2 CEMS were already in use for combustion sources in specific sectors, typical labor hours required for developing QA plans and performing fuel sampling), and an estimate of incremental activities required to comply with the rule. Existing models, such as EPA's CEMS cost model, were used across sectors to ensure consistency of cost inputs and assumptions.

The most important elements affecting the data quality for this analysis include the number of affected facilities in each source category, the number and types of combustion units at each facility, the number and types of production processes that emit GHGs, process inputs and outputs (especially for monitoring procedures that involve a carbon mass balance), and the measurements that are already being made for reasons not associated with the proposed rule (to allow only the incremental costs to be estimated). Many of the affected sources categories, especially those that are the largest emitters of GHGs (e.g., electric utilities, industrial boilers, petroleum refineries, cement plants, iron and steel production, pulp and paper) are subject to national emission standards. In the development of those national standards, detailed background information was gathered to characterize the industry (e.g., number of facilities, types of processes, capacity), and this information was a valuable source of high quality data. The background information for standards development, often collected from industry surveys, was supplemented from numerous sources, including industry surveys from the U.S. Census Bureau, trade associations, and operating permits, for example. Information on measurements that are already made (and thus would not be associated with the proposed rule) was obtained from discussions with industry representatives, knowledge gained from previous site visits, and other sources. The data collected to characterize the facilities in the various source categories are judged to be of good quality and the best that is publicly available.

Other elements affecting the quality of the data include estimates of labor hours to perform specific activities, cost of labor, and cost of monitoring equipment. Estimates of labor hours were based on previous analyses of the costs of monitoring, reporting, and recordkeeping for other rules; information from the industry characterization on the number of units or process inputs and outputs to be monitored, and engineering judgment. Labor costs were taken from the

BLS and adjusted to account for overhead. Monitoring costs were generally based on cost algorithms or approaches that had been previously developed, reviewed, accepted as adequate, and used specifically to estimate the costs associated with various types of measurements and monitoring. The data quality associated with these elements of the cost analysis is analogous to the quality of data used in the development of numerous other Information Collection Requests for the different industrial source categories.

SECTION 4
ENGINEERING COST ANALYSIS

4.1 Introduction

EPA estimated costs of complying with the proposed rule for process emissions of GHGs in each affected industrial facility, as well as emissions from stationary combustion sources at industrial facilities and other facilities, and emissions of GHGs from mobile sources. EPA used available industry and EPA data to characterize conditions at affected sources. Incremental monitoring, recordkeeping, and reporting activities were then identified for each type of facility, and the associated costs were estimated. We present the reporting and verification requirements by source categories in Table 4-1.

Table 4-1. Selected Reporting Thresholds and Reporting Requirements

Subpart	Source Category	Reporting and Verification
D—Electricity Generation (§98.40)	All facilities	See reporting requirements for stationary combustion.
E—Adipic Acid Production (§98.50)	Stationary combustion	See reporting requirements for stationary combustion
	Production	(a) Annual N_2O emissions from adipic acid production in metric tons; (b) Annual adipic acid production capacity (in metric tons); (c) Annual adipic acid production, in units of metric tons of adipic acid produced; (d) Number of facility operating hours in calendar year; (e) Emission rate factor used (lb N_2O/ton adipic acid); (f) Abatement technology used (if applicable); (g) Abatement technology efficiency (percent destruction); and (h) Abatement utilization factor (percent of time that abatement system is operating).
F—Aluminum Production (§98.60)	Stationary combustion	See reporting requirements for stationary combustion.
	Production	(a) Annual aluminum production in metric tons; (b) Type of smelter technology used; (c) The following PFC-specific information on an annual basis: (1) Total perfluoromethane and perfluoroethane emissions from anode effects in all prebake and Søderberg electolysis cells combined; (2) Anode effect minutes per cell-day, anode effect frequency (AE/cell-day), anode effect duration (minutes); and (3) Smelter-specific slope coefficient and the last date when the smelter-specific-slope coefficient was measured; (d) Method used to measure the frequency and duration of anode effects; (e) The following CO_2-specific information for prebake cells on an annual basis: (1) Total anode consumption; and (2) Total CO_2 emissions from the smelter; (f) The following CO_2-specific information for Søderberg cells on an annual basis: (1) Total paste consumption; and (2) Total CO_2 emissions from the smelter; (g) Smelter-specific inputs to the CO_2 process equations (e.g., levels of sulfur and ash) that were used in the calculation, on an annual basis; and (h) Exact data elements required will vary depending on smelter technology (e.g., point-feed prebake or Søderberg).

(continued)

Table 4-1. Selected Reporting Thresholds and Reporting Requirements (continued)

Subpart	Source Category	Reporting and Verification
G—Ammonia Manufacturing (§98.70)	Stationary combustion	See reporting requirements for stationary combustion.
	Production	(a) Annual CO_2 emissions from ammonia manufacturing process (metric tons); (b) Total quantity of feedstock consumed for ammonia manufacturing; and (c) Monthly analyses of carbon content for each feedstock used in ammonia manufacturing (kg carbon/kg of feedstock).
H—Cement Production (§98.80)	Fuel combustion at kilns and any other Stationary combustion unit	See reporting requirements for stationary combustion.
	Production	(a) The total CO_2 emissions from all kilns at the facility combined (in metric tons); (b) Annual clinker production (tons); (c) Number of kilns; (d) Annual CKD production (in metric tons); (e) Total annual fraction of CKD recycled to the kiln (as a percentage); (f) Annual analysis of carbonate composition (by carbonate); (g) Total annual fraction of calcination achieved (for each carbonate, percent); (h) Site-specific emission factor (metric tons CO_2/metric ton clinker produced); (i) Organic carbon content of the raw material (percent); (j) Annual consumption of raw material (metric tons); and (k) Facilities that use CEMS must following the reporting requirements of 98.36(d)(iv).
I—Electronics Manufacturing (§98.90)	Stationary combustion	See reporting requirements for stationary combustion.
	Production	(a) Emissions of each GHG emitted from all plasma etching processes, all chamber cleaning, all chemical vapor deposition processes, and all heat transfer use, respectively; (b) The method, mass of input F-GHG gases, and emission factors used for estimating F-GHG emissions; (c) Production in terms of substrate surface area (e.g., silicon, PV-cell, LCD); (d) Factors used for gas process utilization and by-product formation, and the source and uncertainty for each factor; (e) The verified DRE and its uncertainty for each abatement device used, if you have verified the DRE pursuant to §98.94(c); (f) Fraction of each gas fed into each process type with abatement devices; (g) Description of abatement devices, including the number of devices of each manufacturer and model; (h) For heat transfer fluid emissions, inputs in the mass-balance equation; (i) Example calculations for F-GHG, N_2O, and heat transfer fluid emissions; and (j) Estimate of the overall uncertainty in the emissions estimate.
J—Ethanol Production (§98.100)	Onsite stationary combustion	See reporting requirements for stationary combustion.
	Onsite landfills	See reporting requirements for landfills.
	Onsite wastewater treatment	See reporting requirements for wastewater treatment.
K—Ferroalloy Production (§98.110)	Stationary combustion	See reporting requirements for stationary combustion.
	Production	(a) Annual CO_2 emissions from each electric arc furnace used for ferroalloy production, in metric tons and the method used to estimate these emissions; (b) Annual CH_4 emissions from each electric arc furnaces used for the production of any ferroalloy listed in Table K-1 of this subpart; (c) Facility ferroalloy product production capacity (metric tons); (d) Annual facility production quantity for each ferroalloy product (metric tons); (e) Number of facility operating hours in calendar year; and (f) If the carbon balance procedure is used, report for each carbon-containing input and output material consumed or used (other than fuel), the information specified in paragraphs (f)(1) and (2) of this section; (1) Annual material quantity (in metric tons); and (2) Annual average of the monthly carbon content determinations for each material and the method used for the determination (e.g., supplier provided information, analyses of representative samples you collected).

(continued)

Table 4-1. Selected Reporting Thresholds and Reporting Requirements (continued)

Subpart	Source Category	Reporting and Verification
L—Fluorinated Greenhouse Gas Production (§98.120)	Stationary combustion	See reporting requirements for stationary combustion.
	Production	(a) For each production process at the facility, report: (1) The total mass of the fluorinated GHG produced in metric tons, by chemical, (2) The total mass of each reactant fed into the production process in metric tons, by chemical, (3) The total mass of each reactant permanently removed from the production process in metric tons, by chemical, (4) The total mass of the fluorinated GHG product removed from the production process and destroyed, (5) The mass of each by-product generated, (6) The mass of each by-product destroyed at the facility, (7) The mass of each by-product recaptured and sent off-site for destruction, (8) The mass of each by-product recaptured for other purposes, and (9) The mass of each fluorinated GHG emitted; (b) Where missing data have been estimated pursuant to §98.125, report: (1) The reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data; and (2) Where the missing data have been estimated pursuant to §98.125(a)(3), you shall also report the rationale for the methods used to estimate the missing data and why the methods specified in §98.125(a)(1) and (a)(2) would lead to a significant under- or overestimate of the parameter(s). (c) A fluorinated GHG production facility that destroys fluorinated GHGs shall report the results of the annual fluorinated GHG concentration measurements at the outlet of the destruction device, including: (1) Flow rate of fluorinated GHG being fed into the destruction device in kg/hr. (2) Concentration (mass fraction) of fluorinated GHG at the outlet of the destruction device. (3) Flow rate at the outlet of the destruction device in kg/hr. (4) Emission rate calculated from paragraphs(c)(2) and (c)(3) of this section in kg/hr. (d) A fluorinated GHG production facility that destroys fluorinated GHGs shall submit a one-time report containing the following information: (1) Destruction efficiency (DE) of each destruction unit. (2) Test methods used to determine the destruction efficiency. (3) Methods used to record the mass of fluorinated GHG destroyed. (4) Chemical identity of the fluorinated GHG(s) used in the performance test conducted to determine DE. (5) Name of all applicable federal or state regulations that may apply to the destruction process. (6) If any process changes affect unit destruction efficiency or the methods used to record mass of fluorinated GHG destroyed, then a revised report must be submitted to reflect the changes. The revised report must be submitted to EPA within 60 days of the change.
M—Food Processing (§98.130)	Onsite stationary combustion	See reporting requirements for stationary combustion.
	Onsite landfills	See reporting requirements for landfills.
	Onsite wastewater treatment	See reporting requirements for wastewater treatment.
N—Glass Production (§98.140)	Stationary combustion	See reporting requirements for stationary combustion.
	Production	(a) Annual process emissions of CO_2 from each continuous glass melting furnace, in metric tons/yr.; (b) Annual quantity of each carbonate-based raw material, in metric tons/yr.; (c) Annual quantity of glass produced, in metric tons/yr.; and (d) If process CO_2 emissions are calculated based on data provided by the raw material supplier according to §98.143(a)(1), the carbonate-based mineral mass fraction (as percent) for each carbonate-based raw material charged to a continuous glass melting furnace.

(continued)

Table 4-1. Selected Reporting Thresholds and Reporting Requirements (continued)

O—HCFC-22 Production and HFC-23 Destruction (§98.150)	Stationary combustion	See reporting requirements for stationary combustion.
	Production facilities	(a) For each production process at the facility report: (1) The mass of HCFC-22 produced in metric tons; (2) The mass of reactants fed into the process in metric tons of reactant; (3) The mass (in metric tons) of materials other than HCFC-22 and HFC-23 (i.e., unreacted reactants, HCl and other by-products) that occur in more than trace concentrations and that are permanently removed from the process; (4) The method for tracking startups, shutdowns, and malfunctions and HFC-23 generation/emissions during these events; (5) The names and addresses of facilities to which any HFC-23 was sent for destruction, and the quantities of HFC-23 (metric tons) sent to each; (6) The total mass of the HFC-23 generated in metric tons; (7) The mass of any HFC-23 packaged for sale in metric tons; (8) The mass of any HFC-23 sent off site for destruction in metric tons; (9) The mass of HFC-23 emitted in metric tons; (b) Where missing data have been estimated pursuant to §98.155, the designated representative of the HCFC-22 production facility shall report the reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data; and (1) Where the missing data have been estimated pursuant to§98.155(a)(3), the designated representative shall also report the rationale for the methods used to estimate the miss significant under- or overestimate of the parameter(s).
	HFC-23 destruction facilities	Report the following: (1) The mass of HFC-23 fed into the thermal oxidizer, (2) The mass of HFC-23 destroyed, and (3) The mass of HFC-23 emitted from the thermal oxidizer. Report the results of the facility's annual HFC-23 concentration measurements at the outlet of the destruction device, including the following: (1) The flow rate of HFC-23 being fed into the destruction device in kg/hr, (2) The concentration (mass fraction) of HFC-23 at the outlet of the destruction device, (3) The flow rate at the outlet of the destruction device in kg/hr, and (4) The emission rate calculated from (2) and (3) in kg/hr. Destruction facility shall also submit a one-time report including the following: (1) The destruction unit's destruction efficiency (DE), (2) The methods used to determine the unit's destruction efficiency, (3) The methods used to record the mass of HFC-23 destroyed, (4) The name of other relevant federal or state regulations that may apply to the destruction process, and (5) If any changes to the unit's destruction efficiency or methods used to record volume destroyed occurred, then these changes must be reflected in a revision to this report. The revised report must be submitted to EPA within 60 days of the change.

(continued)

Table 4-1. Selected Reporting Thresholds and Reporting Requirements (continued)

Subpart	Source Category	Reporting and Verification
P—Hydrogen Production (§98.160)	Stationary combustion	See reporting requirements for stationary combustion
	Production	Annual CO_2 process emissions from hydrogen production process units and (a) Annual total consumption of feedstock for hydrogen production; annual total of hydrogen produced; and annual total of ammonia produced, if applicable; (b) Monthly analyses of carbon content for each feedstock used in hydrogen production (kg carbon/kg of feedstock); and (c) Facilities using CEMs must follow reporting requirements in §98.36(d)(iv)
Q—Iron & Steel Production (§98.170)	Stationary combustion	See reporting requirements for stationary combustion.
	Production	Report the following information for coke pushing and for each taconite indurating furnace; basic oxygen furnace; non-recovery coke oven battery; sinter process; EAF; argon-oxygen decarburization vessel; and direct reduction furnace, as applicable: (a) Annual CO_2 emissions by calendar quarters; (b) Annual total for all process inputs and outputs when the carbon balance is used for specific processes by calendar quarters (short tons); (c) Annual production quantity (in metric tons) for taconite pellets, coke, sinter, iron, and raw steel by calendar quarters; (d) Production capacity (in tons per year) for the production of taconite pellets, coke, sinter, iron, and raw steel; (e) Annual operating hours for taconite furnaces, coke oven batteries, sinter production, blast furnaces, direct reduced iron furnaces, and electric arc furnaces; (f) Site-specific emission factor for all process units for which the site-specific emission factor approach is used; and (g) Facilities using CEMs must follow reporting requirements in §98.36(d)(iv).
R—Lead Production (§98.180)	Stationary combustion	See reporting requirements for stationary combustion.
	Production	(a) Total annual CO_2 emissions from each smelting furnace operated at your facility for lead production (metric tons and the method used to estimate emissions); (b) Facility lead product production capacity (metric tons); (c) Annual facility production quantity (metric tons); (d) Number of facility operating hours in calendar year; (e) For each carbon-containing input material consumed or used (other than fuel), report: (1) Annual material quantity (in metric tons); and (2) Annual weighted average carbon content determined for material and the method used for the determination (e.g., supplier provided information, analyses of representative samples you collected).
S—Lime Manufacturing (§98.190)	Stationary combustion	See reporting requirements for stationary combustion.
	Production	For each lime kiln, report (a) Annual CO_2 process emissions; (b) Annual lime production (in metric tons); (c) Annual lime production capacity (in metric tons) per facility; (d) All monthly emission factors; (e) Number of operating hours in calendar year.

(continued)

Table 4-1. Selected Reporting Thresholds and Reporting Requirements (continued)

Subpart	Source Category	Reporting and Verification
T—Magnesium Production (§98.200)	Stationary combustion	See reporting requirements for stationary combustion
	Production	(a) Total GHG emissions for your facility by gas in metric tons and CO_2e; (b) Type of production process (e.g., primary, secondary, die casting); (c) Magnesium production amount in metric tons for each process; (d) Cover gas flow rate and composition; (e) Amount of CO_2 used as a carrier gas during the reporting period; (f) For any missing data, you must report the length of time the data were missing, the method used to estimate emissions in their absence, and the quantity of emissions thereby estimated; (g) The facility's cover gas usage rate; and (h) If applicable, an explanation of any change greater than 30 percent in the facility's cover gas usage rate (e.g., installation of new melt protection technology or leak discovered in the cover gas delivery system that resulted in increased consumption).
U—Misc. Uses of Carbonate (§98.210)	Stationary combustion	See reporting requirements for stationary combustion.
	Production	(a) Annual CO_2 emissions from miscellaneous carbonate use (in metric tons); (b) Annual carbonate consumption (by carbonate type in tons); (c) Annual fraction calcinations ; and (d) Average annual mass fraction of carbonate-based mineral in carbonate-based raw material by carbonate type.
V—Nitric Acid Production (§98.220)	Stationary combustion	See reporting requirements for stationary combustion.
	Production	For each nitric acid production line, report annual N_2O process emissions and (a) Annual nitric acid production capacity (metric tons); (b) Annual nitric acid production (metric tons); (c) Number of operating hours in the calendar year (hours); (d) Emission factor(s) used (lb N_2O/ton of nitric acid produced); (e) Type of nitric acid process used; (f) Abatement technology used (if applicable); (g) Abatement utilization factor (percent of time that abatement system is operating); and (h) Abatement technology efficiency.
W—Oil & Natural Gas Systems (§98.230)	Stationary combustion	See reporting requirements for stationary combustion.
	Production	(a) Annual emissions reported separately for each of the operations listed in (a)(1) through (6) of this paragraph. Within each operation, emissions from each source type must be reported in the aggregate. For example, an underground natural gas storage facility with multiple reciprocating compressors must report emissions from all reciprocating compressors as an aggregate number. (1) Offshore petroleum and natural gas production facilities; (2) Onshore natural gas processing facilities; (3) Onshore natural gas transmission compression facilities; (4) Underground natural gas storage facilities; (5) Liquefied natural gas storage facilities; (6) Liquefied natural gas import and export facilities; (b) Emissions reported separately for standby equipment; (c) Emissions calculated for these sources shall assume no CO_2 capture and transfer offsite; (d) Activity data for each aggregated source type level for which emissions are being reported. (e) Engineering estimate of total component count; (f) Total number of compressors and average operating hours per year for compressors for each operation listed in paragraphs (a)(1) through (6) of this section; (g) Minimum, maximum and average throughput for each operation listed in paragraphs (a)(1) through (6) of this section; (h) Specification of the type of any control device used, including flares, for any source type listed in 98.232(a); (i) For offshore petroleum and natural gas production facilities, the number of connected wells, and whether they are producing oil, gas, or both; and (j) Detection and measurement instruments used.

(continued)

Table 4-1. Selected Reporting Thresholds and Reporting Requirements (continued)

Subpart	Source Category	Reporting and Verification
X—Petrochemical Production (§98.240)	Stationary combustion	See reporting requirements for stationary combustion.
	Onsite wastewater treatment	See reporting requirements for onsite wastewater treatment.
	Production	(a) Facilities using the mass balance methodology in §98.243(a)(2) must report the information specified in paragraphs (a)(1) through (9) of this section for each type of petrochemical produced, reported by process unit; (1) Identification of the petrochemical process; (2) Annual CO_2 emissions calculated using Equation X-4 of this subpart; (3) Methods used to determine feedstock and product flows and carbon contents; (4) Number of actual and substitute data points for each measured parameter; (5) Annual quantity of each feedstock consumed; (6) Annual quantity of each product and byproduct produced, including all products from integrated processes that are part of the petrochemical production source category; (7) Each carbon content measurement for each feedstock, product, and byproduct; (8) All calculations, measurements, equipment calibrations, certifications, and other information; used to assess the uncertainty in emission estimates and the underlying volumetric flow rates, mass flow rates, and carbon contents of feedstocks and products; and (9) Identification of any combustion units that burned process off-gas; and (b) Each facility that uses CEMS to determine emissions from process vents must report the verification data specified in §98.36(d)(1)(iv).
Y—Petroleum Refineries (§98.250)	Stationary combustion	See reporting requirements for stationary combustion.
	Non-merchant hydrogen production	See reporting requirements for hydrogen production.
	Onsite landfills	See reporting requirements for landfills.
	Onsite wastewater treatment	See reporting requirements for onsite wastewater treatment.
	Catalytic cracking units, traditional fluid coking units, catalytic reforming units, sulfur recovery plants, sour gas sent off-site for sulfur recovery operations, on-site sulfur recovery plants, and coke calcining units	(1) The unit ID number (if applicable); (2) A description of the type of unit (fluid catalytic cracking unit, thermal catalytic cracking unit, traditional fluid coking unit, catalytic reforming unit, sulfur recovery plant, or coke calcining unit); (3) Maximum rated throughput of the unit, in bbl/stream day, metric tons sulfur produced/stream day, or metric tons coke calcined/stream day, as applicable; (4) The calculated CO_2, CH_4, and N_2O annual emissions for each unit, expressed in metric tons of each pollutant emitted; and (5) A description of the method used to calculate the CO_2 emissions for each unit (e.g., reference section and equation number).
	Fluid coking units of the flexicoking type	(1) The unit ID number (if applicable); (2) A description of the type of unit; (3) Maximum rated throughput of the unit, in bbl/stream day; (4) Indicate whether the GHG emissions from the low heat value gas are accounted for in subpart C of this part or §98.253(c); and (5) If the GHG emissions for the low heat value gas are calculated at the flexicoking unit, also report the calculated annual CO_2, CH_4, and N_2O emissions for each unit, expressed in metric tons of each pollutant emitted.
	Asphalt blowing operations	(1) The unit ID number (if applicable); (2) The quantity of asphalt blown; (3) The type of control device used to reduce methane (and other organic) emissions from the unit; and (4) The calculated annual CO_2, CH_4, and N_2O emissions for each unit, expressed in metric tons of each pollutant emitted.
	All other process vents subject to §98.253(j)	(1) The vent ID number (if applicable); (2) The unit or operation associated with the emissions; (3) The type of control device used to reduce methane (and other organic) emissions from the unit, if applicable; and (4) The calculated annual CO_2, CH_4, and N_2O emissions for each unit, expressed in metric tons of each pollutant emitted.

(continued)

Table 4-1. Selected Reporting Thresholds and Reporting Requirements (continued)

Subpart	Source Category	Reporting and Verification
Y—Petroleum Refineries (§98.250) (cont'd)	Equipment leaks, storage tanks, uncontrolled blowdown systems, delayed coking units, and loading operations	(1) The total quantity (in million bbl) of crude oil plus the quantity of intermediate products received from off-site that are processed at the facility in the reporting year; (2) The method used to calculate equipment leak emissions and the calculated, cumulative CH_4 emissions (in metric tons of each pollutant emitted) for all equipment leak sources; (3) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for all storage tanks, except for those used to process unstabilized crude oil; (4) The quantity of unstabilized crude oil received during the calendar year and the cumulative CH_4 emissions (in metric tons of each pollutant emitted) for storage tanks used to process unstabilized crude oil; (5) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for uncontrolled blowdown systems; (6) The total number of delayed coking units at the facility, the number of delayed coking drums per unit, the dimensions and annual number of coke-cutting cycles for each drum, and the cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for delayed coking units; (7) The quantity and types of materials loaded that have an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, and the type of vessels in which the material is loaded; (8) The type of control system used to reduce emissions from the loading of material with an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, if any; and (9) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for loading operations.
	Overall facility	If you have a CEMS that measures CO_2 emissions but that is not required to be used for reporting GHG emissions under this subpart (i.e., a CO_2 CEMS on a process heater stack but the combustion emissions are calculated based on the fuel gas consumption), you must identify the emission source that has the CEMS and report the CO_2 emissions as measured by the CEMS for that emissions source.
Z—Phosphoric Acid Production (§98.260)	Stationary combustion	See reporting requirements for stationary combustion.
	Production	(a) Annual phosphoric acid production by origin of the phosphate rock (in metric tons); (b) Annual phosphoric acid production by concentration of phosphoric acid produced (metric tons); (c) Annual phosphoric acid production capacity; (d) Annual arithmetic average percent inorganic carbon in phosphate rock from batch records; and (e) Annual average phosphate rock consumption from monthly measurement records (in metric tons).
AA—Pulp and Paper Manufacturing (§98.270)	Stationary combustion	See reporting requirements for stationary combustion.
	Onsite landfills	See reporting requirements for landfills.
	Onsite wastewater treatment	See reporting requirements for onsite wastewater treatment.
	Production	(a) Annual emissions of CO_2, biogenic CO_2, CH_4, and N_2O presented by calendar quarter; (b) Total consumption of all biomass fuels by calendar quarter; (c) Total annual quantity of spent liquor solids fired at the facility by calendar quarter; (d) Total annual steam purchases; and (e) Total annual quantities of makeup chemicals (carbonates) used.
BB—Silicon Carbide Production (§98.280)	Stationary combustion	See reporting requirements for stationary combustion
	Production	(a) Annual CO_2 and CH_4 emissions from all silicon carbide production processes combined (in metric tons); (b) Annual production of silicon carbide (in metric tons); (c) Annual capacity of silicon carbide production (in metric tons); (d) Annual operating hours; and (e) Quarterly facility-specific emission factors.

(continued)

Table 4-1. Selected Reporting Thresholds and Reporting Requirements (continued)

Subpart	Source Category	Reporting and Verification
CC—Soda Ash Manufacturing (§98.290)	Fuel combustion at each kiln and from each stationary combustion unit	See reporting requirements for stationary combustion.
	For each soda ash manufacturing line	(a) Annual CO_2 process emissions (metric tons); (b) Number of soda ash manufacturing lines; (c) Annual soda ash production (metric tons) and annual soda ash production capacity; (d) Annual consumption of trona from monthly measurements (metric tons); (e) Fractional purity (i.e., inorganic carbon content) of trona or soda ash (by daily measurements and by monthly average) depending on the components used in Equation CC-2 or CC-3 of this subpart); and (f) Number of operating hours in calendar year.
DD—Sulfur Hexafluoride (SF_6) from Electrical Equipment (§98.300)	Stationary combustion	See reporting requirements for stationary combustion.
	Electric power system	Report the following information for each electric power system, by chemical: (a) Nameplate capacity of equipment containing SF_6 and nameplate capacity of equipment containing each PFC: (1) Existing as of the beginning of the year; (2) New during the year; (3) Retired during the year; (b) Transmission miles (length of lines carrying voltages at or above 34.5 kV); (c) SF_6 and PFC sales and purchases; (d) SF_6 and PFC sent off site for destruction; (e) SF_6 and PFC sent off site to be recycled; (f) SF_6 and PFC returned from off site after recycling; (g) SF_6 and PFC stored in containers at the beginning and end of the year; (h) SF_6 and PFC with or inside new equipment purchased in the year; (i) SF_6 and PFC with or inside equipment sold to other entities; and (j) SF_6 and PFC returned to suppliers.
EE—Titanium Dioxide Production (§98.310)	Stationary combustion	See reporting requirements for stationary combustion
	Production	For each titanium dioxide production line: (a) Annual CO_2 emissions from each chloride process line (metric tons); (b) Annual consumption of calcined petroleum coke (metric tons); (c) Annual production of titanium dioxide (metric tons); (e) Annual production capacity of titanium dioxide (metric tons); and (f) Annual operating hours for each titanium dioxide process line.
FF—Underground Coal Mines (§98.320)	Stationary combustion	See reporting requirements for stationary combustion.
	Production	(a) Quarterly volumetric flow rate measurement results for all ventilation systems, including date and location of measurement; (b) Quarterly CH_4 concentration measurement results for all ventilation systems, including date and location of measurement; (c) Quarterly CEMS volumetric flow data used to calculate CH_4 liberated from degasification systems (summed from daily data); (d) Quarterly CEMS CH_4 concentration data used to calculate CH_4 liberated from degasification systems (average from daily data); (e) Quarterly CH_4 destruction at ventilation and degasification systems; (f) Dates in reporting period where active ventilation of mining operations is taking place; (g) Dates in reporting period when continuous monitoring equipment is not properly functioning; (h) Quarterly averages of temperatures and pressures at the time and at the conditions for which all measurements are made; (i) Quarterly CH_4 liberated from each ventilation well or shaft, and from each degasification system (this includes degasification systems deployed before, during, or after mining operations are conducted in a mine area); (j) Quarterly CH_4 emissions (net) from each ventilation well or shaft, and from each degasification system (this includes degasification systems deployed before, during, or after mining operations are conducted in a mine area); and (k) Quarterly CO_2 emissions from on-site destruction of coal mine gas CH_4, where the gas is not a fuel input for energy generation or use.

(continued)

Table 4-1. Selected Reporting Thresholds and Reporting Requirements (continued)

Subpart	Source Category	Reporting and Verification
GG—Zinc Production (§98.330)	Stationary combustion	See reporting requirements for stationary combustion
	Production	For each Waelz kiln or electrothermic furnace: (a) Annual CO_2 emissions in metric tons, and the method used to estimate emissions; (b) Annual zinc product production capacity (in metric tons); (c) Total number of Waelz kilns and electrothermic furnaces at the facility; (d) Number of facility operating hours in calendar year; (e) If you use the carbon input procedure, report for each carbon-containing input material consumed or used (other than fuel) report: (1) Annual material quantity (in metric tons); and (2) Annual average of the monthly carbon content determinations for each material and the method used for the determination (e.g., supplier provided information, analyses of representative samples you collected).
HH—Landfills (§98.340)	Stationary combustion	See reporting requirements for stationary combustion.
	Production (As required by related source methodology)	(a) Waste disposal for each year of landfilling; (b) Method for estimating waste disposal; (c) Waste composition, if available, in percentage categorized as (1) municipal; (2) construction and demolition; (3) biosolids or biological sludges; (4) industrial, inorganic; (5) industrial, organic; and (6) other, or more refined categories, such as those for which k rates are available in Table HH-1 of this subpart; (d) Method for estimating waste composition; (e) Fraction of CH_4 in landfill gas based on measured values if the landfill has a gas collection system or a default; (f) Oxidation fraction used in the calculations; (g) Degradable organic carbon (DOC) used in the calculations; (h) Decay rate (k) used in the calculations; (i) Fraction of DOC dissimilated used in the calculations; (j) Methane correction factor used in the calculations; (k) Annual methane generation and methane emissions (metric tons/year) according to the methodologies in §98.343(c)(1) through (3). Landfills with gas collection system must separately report methane generation and emissions according to the methodologies in §98.343(c)(3)(i) and (ii) and indicate which values are calculated using the methodologies in §98.343(c)(ii); (l) Landfill design capacity; (m) Estimated year of landfill closure; (n) Total volumetric flow of landfill gas for landfills with gas collection systems; (o) CH_4 concentration of landfill gas for landfills with gas collection systems; (p) Monthly average temperature at which flow is measured for landfills with gas collection systems; (q) Monthly average pressure at which flow is measured for landfills with gas collection systems; (r) Destruction efficiency used for landfills with gas collection systems; (s) Methane destruction for landfills with gas collection systems (total annual, metric tons/year); (t) Estimated gas collection system efficiency for landfills with gas collection systems; (u) Methodology for estimating gas collection system efficiency for landfills with gas collection systems; (v) Cover system description; (w) Number of wells in gas collection system; (x) Acreage and quantity of waste covered by intermediate cap; (y) Acreage and quantity of waste covered by final cap; (z) Total CH_4 generation from landfills; and (aa) Total CH_4 emissions from landfills.

(continued)

Table 4-1. Selected Reporting Thresholds and Reporting Requirements (continued)

Subpart	Source Category	Reporting and Verification
II—Wastewater (§98.350)	Stationary combustion	See reporting requirements for stationary combustion
	Production (As required by related source methodology)	(a) Type of wastewater treatment system; (b) Percent of wastewater treated at each system component; (c) COD; (d) Influent flow rate; (e) B_0; (f) MCF; (g) Methane emissions; (h) Type of oil/water separator (petroleum refineries); (i) Emissions factor for the type of separator (petroleum refineries); (j) Carbon fraction in NMVOC (petroleum refineries); (k) CO_2 emissions (petroleum refineries); (l) Total volumetric flow of digester gas (facilities with anaerobic digesters); (m) CH_4 concentration of digester gas (facilities with anaerobic digesters); (n) Temperature at which flow is measured (facilities with anaerobic digesters); (o) Pressure at which flow is measured (facilities with anaerobic digesters); (p) Destruction efficiency used (facilities with anaerobic digesters); (q) Methane destruction (facilities with anaerobic digesters); and (r) Fugitive methane (facilities with anaerobic digesters).
JJ—Manure Management (§98.360)	Stationary combustion	See reporting requirements for stationary combustion.
	Production (As required by related source methodology)	(a) Type(s) of manure management system; (b) Animal population (by animal type); (c) Monthly total volatile solids content of excreted manure; (d) Percent of manure handled in each manure management system component. (e) B_0 value used; (f) Methane conversion factor used; (g) Average animal mass (for each type of animal); (h) Monthly nitrogen content of excreted manure; (i) N_2O emission factor selected; (j) CH_4 emissions; (k) N_2O emissions; (l) Total annual volumetric biogas flow (for systems with digesters); (m) Average annual CH_4 concentration (for systems with digesters); (n) Temperature at which gas flow is measured (for systems with digesters); (o) Pressure at which gas flow is measured (for systems with digesters); (p) Destruction efficiency used (for systems with digesters); (q) Methane destruction (for systems with digesters); and (r) Methane generation from the digesters.
KK—Suppliers of Coal (§98.370)	Coal mine owner or operator	(1) The name and MSHA ID number of the mine; (2) The name of the operating company; (3) Annual CO_2 emissions; (4) By rank, the total annual quantity in tons of coal produced; (5) The annual weighted carbon content of the coal as calculated according to §98.373; (6) If Method 1 was used to determine CO_2 mass emissions, you must report daily mass fraction of carbon in coal measured by ultimate analysis and daily amount of coal supplied; (7) If Method 2 was used to determine CO_2 mass emissions, you must report: (i) All of the data used to construct the carbon vs. Btu/lb correlation graph; (ii) Slope of the correlation line; and (iii) The R-square (R^2) value of the correlation; and (8) If Method 3 was used to determine CO_2 mass emissions, you must report daily GCV of coal measured by proximate analysis and daily amount of coal supplied.

(continued)

Table 4-1. Selected Reporting Thresholds and Reporting Requirements (continued)

Subpart	Source Category	Reporting and Verification
KK—Suppliers of Coal (§98.370) (cont'd)	Coal importers	(1) The total annual quantity in tons of coal imported into the United States by the importer, by rank, and country of origin; (2) Annual CO_2 emissions; (3) The annual weighted carbon content of the coal as calculated according to §98.373; (4) If Method 1 was used to determine CO_2 mass emissions, you must report mass fraction of carbon in coal per shipment measured by ultimate analysis and amount of coal supplied per shipment; (5) If Method 2 was used to determine CO_2 mass emissions, you must report: (i) All of the data used to construct the carbon vs. Btu/lb correlation graph; (ii) Slope of the correlation line; and (iii) The R-square (R^2) value of the correlation; and (6) If Method 3 was used to determine CO_2 mass emissions, you must report GCV in coal per shipment measured by proximate analysis and amount of coal supplied per shipment.
	Coal exporters	(1) The total annual quantity in tons of coal exported from the United States by rank and by coal producing company and mine; (2) Annual CO_2 emissions; (3) The annual weighted carbon content of the coal as calculated according to §98.373; (4) If Method 1 was used to determine CO_2 mass emissions, you must report mass fraction of carbon in coal per shipment measured by ultimate analysis and amount of coal supplied per shipment; (5) If Method 2 was used to determine CO_2 mass emissions, you must report: (i) All of the data used to construct the carbon vs. Btu/lb correlation graph; (ii) Slope of the correlation line; and (iii) The R-square (R^2) value of the correlation; and (6) If Method 3 was used to determine CO_2 mass emissions, you must report GCV in coal per shipment measured by proximate analysis and amount of coal supplied per shipment.
	Waste coal reclaimers	(1) By rank, the total annual quantity in tons of waste coal produced; (2) Mine and state of origin if waste coal is reclaimed from mines that are no longer operating. (3) Annual CO_2 emissions; (4) The annual weighted carbon content of the coal as calculated according to §98.373; (5) If Method 1 was used to determine CO_2 mass emissions, you must report mass fraction of carbon in coal per shipment measured by ultimate analysis and amount of coal supplied per shipment; (6) If Method 2 was used to determine CO_2 mass emissions, you must report: (i) All of the data used to construct the carbon vs. Btu/lb correlation graph; (ii) Slope of the correlation line; and (iii) The R-square (R^2) value of the correlation; and (7) If Method 3 was used to determine CO_2 mass emissions, you must report GCV in coal per shipment measured by proximate analysis and amount of coal supplied per shipment.
LL—Suppliers of Coal-based Liquid Fuels (§98.380)	Producers	(1) The total annual volume of each coal-based liquid supplied to the economy (in standard barrels); and (2) The total annual CO_2 emissions in metric tons associated with each coal-based liquid supplied to the economy, calculated according to §98.383(a).
	Importers	(1) The total annual volume of each imported coal-based liquid (in standard barrels); and (2) The total annual CO_2 emissions in metric tons associated with each imported coal-based liquid, calculated according to §98.383(a).
	Exporters	(1) The total annual volume of each exported coal-based liquid (in standard barrels); and (2) The total annual CO_2 emissions in metric tons associated with each exported coal-based liquid, calculated according to §98.383(a).

(continued)

Table 4-1. Selected Reporting Thresholds and Reporting Requirements (continued)

Subpart	Source Category	Reporting and Verification
MM—Suppliers of Petroleum Products (§98.390)	Refiners	(1) CO_2 emissions in metric tons for each petroleum product and natural gas liquid (ex refinery gate), calculated according to §98.393(a) or (g); (2) CO_2 emissions in metric tons for each petroleum product or natural gas liquid that enters the refinery annually as a feedstock to be further refined or otherwise used onsite, calculated according to §98.393(b) or (g); (3) CO_2 emissions in metric tons from each type of biomass feedstock co-processed with petroleum feedstocks, calculated according to §98.393(c); (4) The total sum of CO_2 emissions from all products, calculated according to §98.393(d); (5) The total volume of each petroleum product and natural gas liquid associated with the CO_2 emissions reported in paragraphs (a)(1) and (2) of this section, separately, and the volume of the biomass-based component of each petroleum product reported in this paragraph that was produced by blending a petroleum-based product with a biomass-based product; if a determination cannot be made whether the material is a petroleum product or a natural gas liquid, it shall be reported as a petroleum product; (6) The total volume of any biomass co-processed with a petroleum product associated with the CO_2 emissions reported in paragraph (a)(3) of this section; (7) The measured density and/or mass carbon share for any petroleum product or natural gas liquid for which CO_2 emissions were calculated using Calculation Methodology 2 of this section, along with the selected method from §98.394(c) and the calculated EF; (8) The total volume of each distillate fuel oil product or feedstock reported in paragraph (a)(5) of this section that contains less than 15 ppm sulfur content and is free from marker solvent yellow 124 and dye solvent red 164; and (9) All of the following information for all crude oil feedstocks used at the refinery: (i) Batch volume (in standard barrels), (ii) API gravity of the batch, (iii) Sulfur content of the batch, and (iv) Country of origin of the batch.
	Importers	(1) CO_2 emissions in metric tons for each imported petroleum product and natural gas liquid, calculated according to §98.393(a); (2) Total sum of CO_2 emissions, calculated according to §98.393(e); (3) The total volume of each imported petroleum product and natural gas liquid associated with the CO_2 emissions reported in paragraph (b)(1) of this section as well as the volume of the biomass-based component of each petroleum product reported in this paragraph that was produced by blending a petroleum-based product with a biomass-based product; if you cannot determine whether the material is a petroleum product or a natural gas liquid, you shall report it as a petroleum product; (4) The measured density and/or mass carbon share for any imported petroleum product or natural gas liquid for which CO_2 emissions were calculated using Calculation Methodology 2 of this section, along with the selected method from §98.394(c) and the calculated EF; and (5) The total volume of each distillate fuel oil product reported in paragraph (b)(1) of this subpart that contains less than 15 ppm sulfur content and is free from marker solvent yellow 124 and dye solvent red 164.
	Exporters	(1) CO_2 emissions in metric tons for each exported petroleum product and natural gas liquid, calculated according to §98.393(a); (2) Total sum of CO_2 emissions, calculated according to §98.393(e); (3) The total volume of each exported petroleum product and natural gas liquid associated with the CO_2 emissions reported in paragraph (c)(1) of this section as well as the volume of the biomass-based component of each petroleum product reported in this paragraph that was produced by blending a petroleum-based product with a biomass-based product; if you cannot determine whether the material is a petroleum product or a natural gas liquid, you shall report it as a petroleum product; (4) The measured density and/or mass carbon share for any petroleum product or natural gas liquid for which CO_2 emissions were calculated using Calculation Methodology 2 of this subpart, along with the selected method from §98.394(c) and the calculated EF; and (5) The total volume of each distillate fuel oil product reported in paragraph (c)(1) of this section that contains less than 15 ppm sulfur content and is free from marker solvent yellow 124 and dye solvent red 164.

(continued)

Table 4-1. Selected Reporting Thresholds and Reporting Requirements (continued)

Subpart	Source Category	Reporting and Verification
NN—Suppliers of Natural Gas and Natural Gas Liquids (§98.400)	Natural gas processing plants	(1) The total annual quantity in barrels of NGLs produced for sale or delivery on behalf of others in the following categories: propane, natural butane, ethane, and isobutane, and all other bulk NGLs as a single category; and (2) The total annual CO_2 mass emissions associated with the volumes in paragraph (a)(1) of this section and calculated in accordance with §98.403.
	Local distribution companies	(1) The total annual volume in Mcf of natural gas received by the local distribution company for redelivery to end users on the local distribution company's distribution system; (2) The total annual CO_2 mass emissions associated with the volumes in paragraph (b)(1) of this section and calculated in accordance with §98.403; (3) The total natural gas volumes received for redelivery to downstream gas transmission pipelines and other local distribution companies; (4) The name and EPA and EIA identification code of each individual covered facility, and the name and EIA identification code of any other end-user for which the local gas distribution company delivered greater than or equal to 460,000 Mcf during the calendar year, and the total natural gas volumes actually delivered to each of these end-users; and (5) The annual volume in Mcf of natural gas delivered by the local distribution company to each of the following end-use categories; for definitions of these categories, refer to EIA Form 176 and Instructions: (i) residential consumers, (ii) commercial consumers, (iii) industrial consumers, and (iv) electricity generating facilities; and (6) The total annual CO_2 mass emissions associated with the volumes in paragraph (b)(5) of this section and calculated in accordance with §98.403.
OO—Suppliers of Industrial Greenhouse Gases (§98.410)	Fluorinated GHG or nitrous oxide production facility	(1) Total mass in metric tons of each fluorinated GHG or nitrous oxide produced at that facility; (2) Total mass in metric tons of each fluorinated GHG or nitrous oxide transformed at that facility; (3) Total mass in metric tons of each fluorinated GHG destroyed at that facility; (4) Total mass in metric tons of any fluorinated GHG or nitrous oxide sent to another facility for transformation; (5) Total mass in metric tons of any fluorinated GHG sent to another facility for destruction; (6) Total mass in metric tons of each reactant fed into the production process; (7) Total mass in metric tons of each non-GHG reactant and by-product permanently removed from the process; (8) Mass of used product added back into the production process (e.g., for reclamation); (9) Names and addresses of facilities to which any nitrous oxide or fluorinated GHGs were sent for transformation, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sent to each for transformation; (10) Names and addresses of facilities to which any fluorinated GHGs were sent for destruction, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sent to each for destruction; and (11) Where missing data have been estimated pursuant to §98.415, the reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data; where the missing data have been estimated pursuant to §98.415(a)(3), the report shall explain the rationale for the methods used to estimate the missing data and why the methods specified in §98.415(a)(1) and (a)(2) would lead to a significant under- or overestimate of the parameters.
	Fluorinated GHG production facilities that destroy Fluorinated GHGs	(b) A fluorinated GHG production facility that destroys fluorinated GHGs shall report the results of the annual fluorinated GHG concentration measurements at the outlet of the destruction device, including: (1) Flow rate of fluorinated GHG being fed into the destruction device in kg/hr; (2) Concentration (mass fraction) of fluorinated GHG at the outlet of the destruction device. (3) Flow rate at the outlet of the destruction device in kg/hr; (4) Emission rate calculated from (b)(2) and (b)(3) in kg/hr; (c) A fluorinated GHG production facility that destroys fluorinated GHGs shall submit a one-time report containing the following information: (1) Destruction efficiency (DE) of each destruction unit; (2) Test method used to determine the destruction efficiency; (3) Methods used to record the mass of fluorinated GHG destroyed; (4) Chemical identity of the fluorinated GHG(s) used in the performance test conducted to determine DE; (5) Name of all applicable federal or state regulations that may apply to the destruction process; and (6) If any process changes affect unit destruction efficiency or the methods used to record mass of fluorinated GHG destroyed, then a revised report must be submitted to reflect the changes; the revised report must be submitted to EPA within 60 days of the change.

(continued)

Table 4-1. Selected Reporting Thresholds and Reporting Requirements (continued)

Subpart	Source Category	Reporting and Verification
OO—Suppliers of Industrial Greenhouse Gases (§98.410) (cont'd)	Bulk importer of fluorinated GHGs or N_2O	For each import: (1) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk; (2) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk and sold or transferred to persons other than the importer for use in processes resulting in the transformation or destruction of the chemical; (3) Date on which the fluorinated GHGs or nitrous oxide were imported; (4) Port of entry through which the fluorinated GHGs or nitrous oxide passed; (5) Country from which the imported fluorinated GHGs or nitrous oxide were imported; (6) Commodity code of the fluorinated GHGs or nitrous oxide shipped; (7) Importer number for the shipment; (8) If applicable, the names and addresses of the persons and facilities to which the nitrous oxide or fluorinated GHGs were sold or transferred for transformation, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sold or transferred to each facility for transformation; and (9) If applicable, the names and addresses of the persons and facilities to which the nitrous oxide or fluorinated GHGs were sold or transferred for destruction, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sold or transferred to each facility for destruction.
	Bulk exporter of fluorinated GHGs or N_2O	For each export: (1) Total mass in metric tons of nitrous oxide and each fluorinated GHG exported in bulk; (2) Names and addresses of the exporter and the recipient of the exports; (3) Exporter's Employee Identification Number; (4) Quantity exported by chemical in metric tons of chemical; (5) Commodity code of the fluorinated GHGs and nitrous oxide shipped; (6) Date on which, and the port from which, fluorinated GHGs and nitrous oxide were exported from the United States or its territories; and (7) Country to which the fluorinated GHGs or nitrous oxide were exported.
PP—Suppliers of Carbon Dioxide (CO_2) (§98.420)	Production	(a) Each facility with production process units or CO_2 production wells must report the following information: (1) Total annual mass in metric tons and the weighted average composition of the CO_2 stream captured, extracted, or transferred in either gas, liquid, or solid forms; (2) Annual quantities in metric tons transferred to the following end-use applications by end-use, if known: (i) Food and beverage, (ii) Industrial and municipal water/wastewater treatment, (iii) Metal fabrication, including welding and cutting, (iv) Greenhouse uses for plant growth, (v) Fumigants (e.g., grain storage) and herbicides, (vi) Pulp and paper, (vii) Cleaning and solvent use, (viii) Fire fighting, (ix) Transportation and storage of explosives, (x) Enhanced oil and natural gas recovery, (xi) Long-term storage (sequestration), and (xii) Research and development; and
	Importers and exporters	(b) CO_2 importers and exporters must report the information in paragraphs (a)(1) and (2) at the corporate level.

Note: Many facilities that would be affected by the proposed rule emit GHGs from multiple sources. The facility must assess every source category that could potentially apply to each when determining if a threshold has been exceeded. If the threshold is exceed for any source category, the facility must report emissions from all source categories, including those source categories that do not exceed the applicable threshold.

4.2 Overview of Cost Analysis

The costs of complying with the proposed rule will vary from one facility to another, depending on the types of emissions, the number of affected sources at the facility, existing monitoring, recordkeeping, and reporting activities at the facility, etc. The costs include labor costs for performing the monitoring, recordkeeping, and reporting activities necessary to comply with the proposed rule. For some affected facilities, costs include monitoring, recording, and reporting of GHG emissions from production processes and from stationary combustion units. For other facilities, the only emissions of GHGs are from stationary combustion. All costs referred to in this section are reported in 2006 dollars.

For each source category, we first provide a general overview of baseline reporting (if data are available); two costs components associated with this information collection; labor costs (i.e., the cost of labor by facility staff to meet the information collection requirements of the proposed rule); and capital and operating and maintenance costs (e.g., the cost of purchasing and installing monitoring equipment or contractor costs associated with providing the required information). Additional details of the data, methods, and assumptions underlying the costs are documented in a separate cost appendix and in accompanying Technical Support Documents (TSDs). The TSDs also include information on the assumptions and methods used to identify representative entities or groups of entities used to develop the cost analysis for each subpart.

4.2.1 Baseline Reporting

When data are available to determine how many companies are currently implementing approaches consistent with the proposed methods at the facility level to meet internal GHG management programs or state or voluntary reporting programs at the domestic or international level, we include a discussion of the baseline reporting practices. When data are not available, we are assuming that none of the facilities in these source categories are currently reporting emissions and that many of the proposed requirements will result in “new” or “full” costs to meet reporting requirements. Specifically, we are assuming that there will be additional costs for any sampling and testing in the requirements in proposed methods (i.e., carbon contents of process inputs, such coke, coal, carbonate composition, or actual emissions). We are also assuming that additional costs will be incurred for preparing monitoring and QA/QC plans, performing the calculations, reporting the results, and maintaining records. The only significant element for these sources that we know is performed routinely by all companies is that they have measurements and records of consumption of raw materials such as feedstocks, carbonates, and reducing agents as part of their routine operation for accounting purposes.

4.2.2 Reporting Costs

To ensure consistency in the development of cost estimates across all sources, EPA developed a cost spreadsheet template that each subpart used to compile, document, and calculate per unit reporting costs. Please refer back to Section 3 for information on the subpart process for source categories. Detailed instructions were provided along with the cost spreadsheet template that clearly explained the data to be compiled and calculated. The template included three tables; analysis of reporting thresholds, analysis of monitoring and reporting options, and unit costs for monitoring and reporting. Key variables and data fields were clearly defined to ensure that each sub group developed costs around a standard set of methods and assumptions (e.g., method for annualization of capital costs, interest rate to be applied to capital).

Labor Costs. The costs of complying with and administering this proposed rule include the time of managers, technical, and administrative staff in both the private sector and the public sector. Staff hours are estimated for activities including

- monitoring (private): staff hours to operate and maintain emissions monitoring systems;
- reporting (private): staff hours to gather and process available data and reporting it to EPA through electronic systems; and
- assuring and releasing data (public): staff hours to quality assure, analyze, and release reports.

Staff activities and associated labor costs may vary over time. Thus, cost estimates are developed for start-up, first-time reporting, and subsequent reporting.

Loaded hourly labor rates (also referred to as "wage rates") were developed for several labor categories to represent *the employer costs to use an hour of employees' time* in each of the manufacturing sector labor categories used in this analysis. The labor categories correspond to the job responsibilities of the personnel that are likely to be involved in GHG emissions monitoring activities at the manufacturing facility level to comply with the rulemaking.

For purposes of this study, EPA adopted the methodology used by Cody Rice (2002) to calculate the wage rates for the EPA's Toxics Release Inventory (TRI) Program. Thus, the *wage rates* calculated for different labor categories included the *employer costs for employee compensation* (comprising the basic wages and the corresponding benefits) and *the overhead costs to the employer*.[7]

For each labor category, the following formula was used to calculate the wage rates:

[7] For each employee, the employer also incurs *overhead costs* (comprising the rental costs of the office space, computer hardware and software, telecommunication and other equipments, organizational support, etc.) required for and used by the employee to effectively fulfill his/her job responsibilities. These costs are over and above the employee compensation costs.

*Loaded Hourly Labor Rate ($/hr.) = Basic Wages ($/hr.) * (1 + Benefits Loading Factor + Overhead Loading Factor).*

The *benefits loading factor* corresponds to the relative share of benefits compensation in the total employee compensation (comprising basic wages and benefits). Although the benefits factor tends to vary by labor category and by industry (0.37 to 0.50), for purposes of this analysis, we have assumed the benefits loading factor to remain the same for each labor category across all industries within the manufacturing sector due to a lack of availability of necessary industry-specific data on benefits paid to employees.

The *overhead loading factor* corresponds to the share of overhead costs to the employer relative to the total employee compensation. For purposes of this analysis, we have also adopted the same overhead loading factor that Cody Rice (2002) used in her wage rate calculations. Thus the overhead loading factor that we used in the wage rate calculations remains the same for all labor categories and across all industry types within the manufacturing sector. The overhead loading factor was assumed to be 0.17.

The loaded labor rates for eight labor categories are used in the analysis and are also reported in the appropriate sectors labor cost tables in the following sections. They include

- electricity manager: $88.79;
- refinery manager: $101.31;
- industrial manager: $71.03;
- lawyer: $101.00;
- electricity engineer/technician: $60.84;
- refinery engineer/technician: $63.89;
- industrial engineer/technician: $55.20; and
- administrative support: $29.65.

Capital and O&M Costs. This includes the cost of purchasing and installing monitoring equipment or contractor costs associated with providing the required information. Selected subparts do not require capital expenditures because the selected monitoring option does not require capital equipment or the reporter already owns the necessary monitoring equipment. Equipment costs include both the initial purchase price of monitoring equipment and any facility/process modification that may be required. For example, the cost estimation method for mobile sources involves upstream measurement by the vehicle manufacturers. This may require an upgrade to their test equipment and facility. Based on expert judgment, the engineering costs analyses annualized capital equipment costs with the appropriate lifetime and interest rate assumptions. Cost recovery periods vary by industry (5 to 15 years) with one-time capital costs are amortized at a rate of 7%.

Although not proposed, costs of electricity purchase reporting are included in RIA to demonstrate the cost of this provision on which comment is requested. We estimate the annual cost of this provision if included to be only $376,000, which results in a slight overestimate of costs for the actual proposal. Under this provision, if included in the final rule, all sources required to report under this rule would also be required to report electricity purchase data. This will provide a better understanding of how electricity is used in the economy and the major industrial sectors. Monitoring of electricity purchases is accomplished through accounting of kilowatt hours billed for on utility statements. It was assumed that 1 hour of engineer/technician-level time was required per year for each entity to report their electricity use at a cost of $29.65 per hour. Additional recordkeeping ($1,700 per entity) and reporting ($500) costs were also added to the majority of sectors.

A potentially large number of facilities would need to calculate their emissions in order to determine whether or not they had to report under the proposed rule. Therefore, to further minimize the burden on those facilities, we are proposing that any facility that has an aggregate maximum rated heat input capacity of the stationary fuel combustion units less than 30 mmBtu/hr may presume it has emissions below the threshold. According to our analysis, a facility with stationary combustion units that have a maximum rated heat input capacity of less than 30 mmBtu/hr, operating full time (e.g., 8,760 hours per year) with all types of fossil fuel would not exceed 25,000 metric tons CO_2e/yr (EPA-HQ-OAR-2008-0508-049). Under this approach, we estimate that 30,000 facilities will have to assess whether or not they have to report based on stationary combustion activities. Of the 30,000, approximately 13,000 facilities would likely meet the threshold and have to report. Therefore, an additional 17,000 facilities may have to assess their applicability but potentially not meet the threshold for reporting. The proposed rule requires facilities to follow methodologies in the rule to make a determination. It is assumed that a facility would utilize a fuel sampling methodology. The costs for this activity are outlined below:

- § Planning costs assumed to include:
  - – 2 hours (industrial engineer/technician) for regulatory review
  - – 4 hours (industrial engineer/technician) to resolve questions

– 4 hours (industrial engineer/technician) to develop sampling approach

§ Recordkeeping and reporting costs assumed to include:

– 2 hours (industrial engineer/technician) for data reduction and review

§ Fuel sampling costs assume 1 hour (industrial engineer/technician) and $150 lab cost per sample.

Using the labor costs presented in Section 4.2.2 (industrial engineer/technician—$55.20/hr) the total cost of the determination activity would be $867.60 per facility. These costs would be for a one-time fuel sampling and are based on the costs for monthly fuel sampling outlined in Section 4.3. We are soliciting comment and gathering information on an alternative means of reporting determination that would provide simplified emissions calculation tools for certain source categories. The use of such tools could reduce the cost of the determination activity. The total cost of determination for these 17,000 facilities estimated to be below the selected threshold is not included in the total cost of the rule presented in this RIA.

4.2.3 Cost Analysis Summary by Subpart

At the end of this Section 4, we summarize the total facilities covered, emissions covered, and the cost information for each subpart. The data are the basis for the economic impact analysis described in detail in Section 5 of this document. This chapter provides these data, as well as background information needed to understand the engineering costs analysis conducted for each source and the reporting option selection.

4.3 Subpart C—General Stationary Fuel Combustion Sources & Subpart D—Electricity Generation and other Stationary Combustion Sources

Stationary combustion sources include stationary fossil fuel combustion units producing GHG emissions. Stationary combustion units include electricity generating units, boilers, furnaces, turbines, and kilns, among others. Costs for monitoring GHG emissions from stationary combustion sources were developed for several monitoring categories, listed in Table 4-2. Due to the methodological approaches taken, separate costing analyses were performed for monitoring methods for combustion-related CO_2 emissions and monitoring methods for non-CO_2 emissions (e.g., CH_4 and N_2O). For combustion-related non-CO_2 emissions, EPA will use IPCC default emissions factors. These factors will be applied based on the fuel type used, thus there is minimal cost to reporters for combustion-related non-CO_2 emissions.

For costing purposes, the monitoring categories for CO_2 were divided into those that required the installation of new stack monitoring equipment (namely CEMS) and those that relied on analysis of fuels that are combusted. For the stack monitoring categories, different costs were assumed based on existing configurations of CEMS equipment.

A range of data sources were used to develop these per unit cost estimates. These datasets include information currently collected by EPA under existing programs and other proprietary databases.

For estimating costs for units within the electricity generation sector, data currently collected under the Acid Rain Program was used. The data includes both fuel usage and CEMS equipment installed. Additionally, EPA's EGrid database of electricity generation in the United States contained information on facilities that are not reporting to the Acid Rain Program. The majority of those data are provided to EGrid from DOE's Energy Information Administration (EIA) survey forms. The database Velocity Suite® (Ventyx, 2008) was also used to cross-reference these information sources.

For units in industrial sectors, the primary sources of data on individual units were EPA analyses on certain industrial sectors, and a characterization of the U.S. boiler population. Information on existing CEMS was collected from data already reported to EPA's NO_x Budget Trading Program. An overall examination of the fuels used in the industrial sector was performed using data from EIA's 2002 Manufacturing Energy Consumption Survey (MECS).

For large emitters in the commercial sector, EIA's 2003 Commercial Building Energy Consumption Survey (CBECS) was referenced, as well as EEA's Characterization of the U.S. Industrial Commercial Boiler Population.

From these datasets, the appropriate information on the fuel being used at facilities was gathered. Foremost, data was collected that allowed the determination to be made on whether a solid fuel was being combusted at a large stationary combustion unit. In the event that a solid fuel was combusted by such a large unit, additional details were available to understand existing CEMS equipment and the appropriate upgrade costs to meet the requirements being proposed in this rule. For those facilities that combusted natural gas or petroleum fuels, only a fuel analysis is required, and the appropriate costing scenario was then applied.

4.3.1 Labor Costs

Both first year and annual labor costs were constructed by estimating the number of staff hours required to perform the activities and multiplying them by the relevant wage rate. Wage rates to monetize staff time were obtained from the Bureau of Labor Statistics. Wage rates for other various labor categories (e.g., manager, environmental engineer, engineering technician, administrative support) were used as appropriate. A detailed breakdown of labor costs and other costs for each monitoring category is provided in Table 4-2. Additional cost details for each monitoring category are included in Tables 4-2a to 4-2i. These tables describe the requirements/activities for each category and show the labor hours and costs, consultant costs, and other direct costs (ODCs).

4.3.2 Capital and O&M Costs

In addition to labor costs, some firms must also purchase equipment in order to comply with the proposed rule. Equipment purchase costs are upfront costs, frequently paid for over a period of time. Therefore, these costs are annualized costs over a 15-year timeframe (which corresponds to the expected lifetime of the equipment) and discounted at a rate of 7%. Firms complying with the proposed rule will incur O&M costs each year. These costs can be separated into a labor component, accounted for in the above discussion of labor costs, and other direct costs, including the cost of consumables and all other materials that may be required.

Table 4-2. Per Unit Cost Breakdown by Monitoring Category: Stationary Combustion (2006$)

				Annualized First-time Costs			Annual O&M Costs		
Scenario	**Description**	**Tier**	**Total**	**Labor Costs**	**Equipment Purchase Costs and Other ODCs**	**Total**	**Labor Costs**	**Other Direct Costs**	**Total**
CEMS-Add CO_2 analyzer and flow meter	Applies to non-Part 75, non-EGU (industrial) units where O_2 analyzers will not suffice, e.g., sources with process emissions (cement, lime, glass).	4	$56,040	$24,770	$6,024	$30,793	$20,629	$4,618	$25,247
CEMS-Add CO_2 analyzer only	Applies to non-Part 75, non-EGU (industrial) combustion units and cogens that have a flow monitor and NO_x or SO_2 analyzer	4	$20,593	$7,421	$1,033	$8,454	$9,556	$2,583	$12,139
CEMS-Add flow monitor only	Applies to non-Part 75, non-EGU (industrial) combustion units and cogens that have a CO_2 or O_2 analyzer, consistent fuel and no process emissions. We are assuming that 90% of solid fossil fueled >250 mmBtu units have Part 60 analyzers.	4	$24,511	$6,421	$4,199	$10,620	$11,342	$2,549	$13,891
CEMS part 75 Appendix G (non-ARP): add CO_2 data stream	Part 75 Appendix G oil and gas fired units that will use default factors to calculate emissions. Coal-fired units are assumed to have O_2 or CO_2 diluent in which case they will add the CO_2 data stream to their DAS.	4	$2,500	$0	$0	$0	$2,500	$0	$2,500
CEMS part 75 ARP units—report annual CO_2, methane and nitrous oxide	ARP units already report CO_2 so the only change here is for the annual report.	4	$1,000	$0	$0	$0	$1,000	$0	$1,000
Daily fuel sampling	Continuously measuring fuel use and daily sampling of fuel characteristics for combustion emissions, e.g., refinery, petrochem where process control is in place.	3	$20,466	$2,770	$364	$3,134	$15,284	$2,049	$17,333

(continued)

Table 4-2. Per Unit Cost Breakdown by Monitoring Category: Stationary Combustion (2006$) (continued)

Scenario	Description	Tier	Total	Annualized First-time Costs			Annual O&M Costs		
				Labor Costs	Equipment Purchase Costs and Other ODCs	Total	Labor Costs	Other Direct Costs	Total
Monthly fuel sampling	Continuously measuring fuel use and monthly sampling of fuel characteristics for combustion emissions is sufficient.	3	$6,696	$1,886	$0	$1,886	$2,649	$2,160	$4,809
Periodic in-stack gas sampling	Cost for site-specific EFs by periodically sampling in-stack flue gas for process or combustion emissions (or both).	3	$12,322	$4,234	$0	$4,234	$7,729	$360	$8,089
Periodic off-site flue gas analysis	Cost for site-specific EFs by periodically sampling flue gas for process or combustion emissions (or both). Analysis is off-site.	3	$5,301	$2,174	$0	$2,174	$978	$2,148	$3,126

Table 4-2a. Detailed Summary of Stationary Combustion Monitoring Category Costs: CEMS-Add CO_2 Analyzer and Flow Meter (2006$)

	Labor	Consultants	ODCs	Total
First costs				
Planning	$3,477	$—	$364	$3,841
Select equipment	$9,281	$—	$650	$9,931
Support facilities	$0	$—	$5,400	$5,400
Purchase CEMS hardware	$0	$—	$44,403	$44,403
Install and check CEMS	$2,987	$—	$3,970	$6,957
Performance specification tests	$331	$693	$75	$1,099
QA/QC plan	$1,500	$6,500	$—	$8,000
Subtotal first costs	$17,577	$7,193	$54,862	$79,632
Annualized first costs	$17,577	$7,193	$6,024	$30,793
Annual costs				
Day-to-day activities	$3,533	$—	$1,000	$4,533
Annual RATA	$800	$11,218	$—	$12,019
Cylinder gas audits	$1,325	$—	$1,069	$2,393
Recordkeeping and reporting	$1,214	$—	$50	$1,264
Annual QA and O&M review and update	$2,539	$—	$2,499	$5,038
Subtotal annual costs	$9,411	$11,218	$4,618	$25,247
Total annualized first costs + annual costs	**$26,988**	**$18,411**	**$10,642**	**$56,040**

Table 4-2b. Detailed Summary of Stationary Combustion Monitoring Category Costs: CEMS-Add CO_2 Analyzer Only (2006$)

	Labor	Consultants	ODCs	Total
First costs				
Planning	$1,104	$—	$—	$1,104
Select equipment	$2,602	$—	$355	$2,957
Purchase CEMS hardware	$0	$—	$8,363	$8,363
Install and check CEMS	$2,214	$—	$690	$2,904
Subtotal first costs	$5,921	$—	$9,408	$15,329
Annualized first costs	$6,921	$500	$1,033	$8,454
Annual costs				
Day-to-day activities	$883	$—	$—	$883
Annual RATA	$304	$5,609	$—	$—
Cylinder gas audits	$773	$—	$534	$—
Recordkeeping and reporting	$883	$—	$50	$933
Annual QA and O&M review and update	$1,104	$—	$1,999	$3,103
Subtotal annual costs	$3,947	$5,609	$2,583	$12,139
Total annualized first costs + annual costs	**$10,867**	**$6,109**	**$3,616**	**$20,593**

Table 4-2c. Detailed Summary of Stationary Combustion Monitoring Category Costs: CEMS-Add Flow Monitor Only (2006$)

	Labor	Consultants	ODCs	Total
First costs				
Planning	$1,104	$—	$—	$1,104
Select equipment	$2,602	$—	$355	$2,957
Purchase CEMS hardware	$0	$—	$31,800	$31,800
Install and check CEMS	$1,214	$—	$690	$1,904
Subtotal first costs	$4,921	$—	$32,845	$37,766
Annualized first costs	$5,921	$500	$4,199	$10,620
Annual costs				
Day-to-day activities	$3,442	$—	$—	$3,442
Annual RATA	$304	$5,609	$—	$5,913
Recordkeeping and reporting	$883	$—	$50	$933
Annual QA and O&M review and update	$1,104	$—	$2,499	$3,603
Subtotal annual costs	$5,733	$5,609	$2,549	$13,891
Total annualized first costs + annual costs	**$11,653**	**$6,109**	**$6,748**	**$24,511**

Table 4-2d. Detailed Summary of Stationary Combustion Monitoring Category Costs: CEMS part 75 Appendix G (non-ARP): Add CO_2 Data Stream (2006$)

	Labor	Consultants	ODCs	Total
Annual reporting	$2,500			$2,500
Total annualized first costs + annual costs	**$2,500**			**$2,500**

Table 4-2e. Detailed Summary of Stationary Combustion Monitoring Category Costs: CEMS part 75 ARP Units—Report Annual CO_2, Methane and Nitrous Oxide (2006$)

	Labor	Consultants	ODCs	Total
Annual reporting	$1,000			$1,000
Total annualized first costs + annual costs	**$1,000**			**$1,000**

Table 4-2f. Detailed Summary of Stationary Combustion Monitoring Category Costs: Daily Fuel Sampling (2006$)

	Labor	Consultants	ODCs	Total
First costs				
Planning	$1,270	$—	$364	$1,634
QA/QC plan	$1,000	$500	$—	$1,500
Subtotal first costs	$2,270	$500	$364	$3,134
Annualized first costs	$2,270	$500	$364	$3,134
Annual costs				
Fuel sampling	$13,297	$—	$—	$13,297
Recordkeeping and reporting	$883	$—	$50	$933
Annual QA and O&M review and update	$1,104	$—	$1,999	$3,103
Subtotal annual costs	$15,284	$—	$2,049	$17,333
Total annualized first costs + annual costs	**$17,553**	**$500**	**$2,413**	**$20,466**

Table 4-2g. Detailed Summary of Stationary Combustion Monitoring Category Costs: Monthly Fuel Sampling (2006$)

	Labor	Consultants	ODCs	Total
First costs				
Planning	$386	$—	$—	$386
QA/QC plan	$1,000	$500	$—	$1,500
Subtotal first costs	$1,386	$500	$—	$1,886
Annualized first costs	$1,386	$500	$—	$1,886
Annual costs				
Fuel sampling	$662	$—	$1,800	$2,462
Recordkeeping and reporting	$883	$—	$50	$933
Annual QA and O&M review and update	$1,104	$—	$310	$1,414
Subtotal annual costs	$2,649	$—	$2,160	$4,809
Total annualized first costs + annual costs	**$4,036**	**$500**	**$2,160**	**$6,696**

Table 4-2h. Detailed Summary of Stationary Combustion Monitoring Category Costs: Periodic In-Stack Gas Sampling (2006$)

	Labor	Consultants	ODCs	Total
First costs				
Planning	$1,270	$—	$364	$1,634
Select equipment	$1,000	$—	$100	$1,100
QA/QC plan	$1,000	$—	$500	$1,500
Subtotal first costs	$3,270	$—	$964	$4,234
Annualized first costs	$3,270	$—	$964	$4,234
Annual costs				
Annual in-stock sample	$552	$5,300	$—	$5,852
Recordkeeping and reporting	$883	$—	$50	$933
Annual QA and O&M review and update	$994	$—	$310	$1,304
Subtotal annual costs	$2,429	$5,300	$360	$8,089
Total annualized first costs + annual costs	**$5,698**	**$5,300**	**$1,324**	**$12,322**

Table 4-2i. Detailed Summary of Stationary Combustion Monitoring Category Costs: Periodic Off-Site Flue Gas Analysis (2006$)

	Labor	Consultants	ODCs	Total
First costs				
Planning	$386	$—	$288	$674
QA/QC plan	$1,000	$—	$500	$1,500
Subtotal first costs	$1,386	$—	$788	$2,174
Annualized first costs	$1,386	$—	$788	$2,174
Annual costs		$—		
Fuel sampling	$221	$—	$1,000	$1,221
Recordkeeping and reporting	$883	$—	$50	$933
Annual QA and O&M review and update	$662	$—	$310	$972
Subtotal annual costs	$1,766	$—	$1,360	$3,126
Total annualized first costs + annual costs	**$3,153**	**$—**	**$2,148**	**$5,301**

4.3.3 Units Covered

The number of units estimated to report at the 1,000, 10,000, 25,000 hybrid, and 100,000 ton thresholds are reported in Table 4-3. The unit counts reported in this table cover all subparts of the reporting program with the exception of Subpart H—cement production, Subpart Y—petroleum refineries, and Subpart Q—iron and steel production. In these cases, the engineering workgroups directly estimated labor, capital, and O&M costs associated with monitoring stationary fossil fuel combustion units producing GHG emissions. All estimates were generated using many of the above mentioned industry-specific databases, as well as expert judgment by industry experts and EPA.

4.4 Subpart E—Adipic Acid Production

Overview. Costs were developed for the following proposed monitoring method for estimating N_2O emissions from adipic acid production.

Labor Costs. A majority of the labor costs are associated with planning ($1,800) and sampling and analysis activities ($2,300). These costs cover process emissions.

Capital and O&M Costs. There are no new capital equipment requirements for this subpart. Reporting requires approximately $2,500 of O&M costs related to equipment, performance testing, and travel. These costs cover process emissions.

Table 4-3. Reporting Units by Threshold and Monitoring Category

Subpart	Description	Unit Counts by Tier: Total	Tier 1 or 2	Tier 3	Tier 4	Unit Counts by Monitoring Category: CEMS-Add CO_2 Analyzer and Flow Monitor	CEMS-Add CO_2 Analyzer Only	CEMS Add Flow Monitor Only	CEMS Part 75 Non-ARP: Add CO_2 Data Stream	CEMS Part 75 ARP Units—Report Annual CO_2, Methane and Nitrous Oxide	Daily Fuel Sampling (comb)	Monthly Fuel Sampling (comb)	Periodic In-stack Gas Sampling	Periodic Off-site Flue Gas Analysis
1,000 Threshold														
D	ARP electricity generation	3,279	0	0	3,279	0	0	0	0	3,279	0	0	0	0
C	Non-ARP electricity generation	1,352	1,127	100	125	0	0	125	0	0	0	100	0	0
C	MSW combustion	2	0	0	2	0	0	0	0	2	0	0	0	0
C	General unspecified industrial combustion	94,438	93,659	598	181	48	0	133	0	0	0	598	0	0
H	Cement manufacture	107	0	5	102	99	0	0	3	0	0	0	0	0
S	Lime manufacture	89	0	0	89	89	0	0	0	0	0	0	0	0
V	Nitric acid production	4	0	0	4	4	0	0	0	0	0	0	0	0
G	Ammonia manufacture and urea consumption	24	0	24	0	0	0	0	0	0	0	0	24	0
F	Aluminum production	0	0	0	0	0	0	0	0	0	0	0	0	0
E	Adipic acid production	4	0	4	0	0	0	0	0	0	0	0	4	0
I	Semiconductor manufacture	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	Soda ash manufacture and consumption	5	5	0	0	0	0	0	0	0	0	0	0	0
T	Magnesium production and processing	0	0	0	0	0	0	0	0	0	0	0	0	0
EE	Titanium dioxide production	8	8	0	0	0	0	0	0	0	0	0	0	0
K	Ferroalloy production	6	0	6	0	0	0	0	0	0	0	6	0	0
Z	Phosphoric acid production	14	0	0	14	14	0	0	0	0	0	0	0	0
GG	Zinc production	9	0	9	0	0	0	0	0	0	0	9	0	0
R	Lead production	17	0	17	0	0	0	0	0	0	0	17	0	0
BB	Silicon carbide production and consumption	1	1	0	0	0	0	0	0	0	0	0	0	0
N	Glass	217	0	217	0	0	0	0	0	0	0	217	0	0
C	Cogen	587	0	204	383	0	0	47	151	185	0	204	0	0
P	Hydrogen	77	0	77	0	0	0	0	0	0	0	77	0	0

(continued)

Table 4-3. Reporting Units by Threshold and Monitoring Category (continued)

		Unit Counts by Tier				Unit Counts by Monitoring Category								
Subpart	Description	Total	Tier 1 or 2	Tier 3	Tier 4	CEMS-Add CO_2 Analyzer and Flow Monitor	CEMS-Add CO_2 Analyzer Only	CEMS Add Flow Monitor Only	CEMS Part 75 Non-ARP: Add CO_2 Data Stream	CEMS Part 75 ARP Units—Report Annual CO_2, Methane and Nitrous Oxide	Daily Fuel Sampling (comb)	Monthly Fuel Sampling (comb)	Periodic In-stack Gas Sampling	Periodic Off-site Flue Gas Analysis
10,000 Threshold														
D	ARP electricity generation	3,279	0	0	3,279	0	0	0	0	3,279	0	0	0	0
C	Non-ARP electricity generation	559	334	100	125	0	0	125	0	0	0	100	0	0
C	MSW combustion	2	0	0	2	0	0	0	0	2	0	0	0	0
C	General unspecified industrial combustion	22,120	21,341	598	181	48	0	133	0	0	0	598	0	0
H	Cement manufacture	107	0	5	102	99	0	0	3	0	0	0	0	0
S	Lime manufacture	89	0	0	89	89	0	0	0	0	0	0	0	0
V	Nitric acid production	4	0	0	4	4	0	0	0	0	0	0	0	0
G	Ammonia manufacture and urea consumption	24	0	24	0	0	0	0	0	0	0	0	24	0
F	Aluminum production	0	0	0	0	0	0	0	0	0	0	0	0	0
E	Adipic acid production	4	0	4	0	0	0	0	0	0	0	0	4	0
I	Semiconductor manufacture	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	Soda ash manufacture and consumption	5	5	0	0	0	0	0	0	0	0	0	0	0
T	Magnesium production and processing	0	0	0	0	0	0	0	0	0	0	0	0	0
EE	Titanium dioxide production	8	8	0	0	0	0	0	0	0	0	0	0	0
K	Ferroalloy production	6	0	6	0	0	0	0	0	0	0	6	0	0
Z	Phosphoric acid production	14	0	0	14	14	0	0	0	0	0	0	0	0
GG	Zinc production	9	0	9	0	0	0	0	0	0	0	9	0	0
R	Lead production	16	0	16	0	0	0	0	0	0	0	16	0	0
BB	Silicon carbide production and consumption	1	1	0	0	0	0	0	0	0	0	0	0	0
N	Glass	158	0	158	0	0	0	0	0	0	0	158	0	0
C	Cogen	550	0	167	383	0	0	47	151	185	0	167	0	0
P	Hydrogen	73	0	73	0	0	0	0	0	0	0	73	0	0

(continued)

Table 4-3. Reporting Units by Threshold and Monitoring Category (continued)

		Unit Counts by Tier				Unit Counts by Monitoring Category								
Subpart	Description	Total	Tier 1 or 2	Tier 3	Tier 4	CEMS-Add CO_2 Analyzer and Flow Monitor	CEMS-Add CO_2 Analyzer Only	CEMS Add Flow Monitor Only	CEMS Part 75 Non-ARP: Add CO_2 Data Stream	CEMS Part 75 ARP Units—Report Annual CO_2, Methane and Nitrous Oxide	Daily Fuel Sampling (comb)	Monthly Fuel Sampling (comb)	Periodic In-stack Gas Sampling	Periodic Off-site Flue Gas Analysis
25,000 Threshold														
D	ARP electricity generation	3,279	0	0	3,279	0	0	0	0	3,279	0	0	0	0
C	Non-ARP electricity generation	406	181	100	125	0	0	125	0	0	0	100	0	0
C	MSW combustion	2	0	0	2	0	0	0	0	2	0	0	0	0
C	General unspecified industrial combustion	8,058	7,279	598	181	48	0	133	0	0	0	598	0	0
H	Cement manufacture	107	0	5	102	99	0	0	3	0	0	0	0	0
S	Lime manufacture	89	0	0	89	89	0	0	0	0	0	0	0	0
V	Nitric acid production	4	0	0	4	4	0	0	0	0	0	0	0	0
G	Ammonia manufacture and urea consumption	24	0	24	0	0	0	0	0	0	0	0	24	0
F	Aluminum production	0	0	0	0	0	0	0	0	0	0	0	0	0
E	Adipic acid production	4	0	4	0	0	0	0	0	0	0	0	4	0
I	Semiconductor manufacture	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	Soda ash manufacture and consumption	5	5	0	0	0	0	0	0	0	0	0	0	0
T	Magnesium production and processing	0	0	0	0	0	0	0	0	0	0	0	0	0
EE	Titanium dioxide production	8	8	0	0	0	0	0	0	0	0	0	0	0
K	Ferroalloy production	6	0	6	0	0	0	0	0	0	0	6	0	0
Z	Phosphoric acid production	14	0	0	14	14	0	0	0	0	0	0	0	0
GG	Zinc production	8	0	8	0	0	0	0	0	0	0	8	0	0
R	Lead production	13	0	13	0	0	0	0	0	0	0	13	0	0
BB	Silicon carbide production and consumption	1	1	0	0	0	0	0	0	0	0	0	0	0
N	Glass	55	0	55	0	0	0	0	0	0	0	55	0	0
C	Cogen	485	0	102	383	0	0	47	151	185	0	102	0	0
P	Hydrogen	51	0	51	0	0	0	0	0	0	0	51	0	0

(continued)

Table 4-3. Reporting Units by Threshold and Monitoring Category (continued)

		Unit Counts by Tier				Unit Counts by Monitoring Category								
Subpart	Description	Total	Tier 1 or 2	Tier 3	Tier 4	CEMS-Add CO_2 Analyzer and Flow Monitor	CEMS-Add CO_2 Analyzer Only	CEMS Add Flow Monitor Only	CEMS Part 75 Non-ARP: Add CO_2 Data Stream	CEMS Part 75 ARP Units—Report Annual CO_2, Methane and Nitrous Oxide	Daily Fuel Sampling (comb)	Monthly Fuel Sampling (comb)	Periodic In-stack Gas Sampling	Periodic Off-site Flue Gas Analysis
100,000 Threshold														
D	ARP electricity generation	3,279	0	0	3,279	0	0	0	0	0	0	0	0	0
C	Non-ARP electricity generation	175	66	58	51	0	0	0	0	0	0	0	0	0
C	MSW combustion	0	0	0	0	0	0	0	0	0	0	0	0	0
C	General unspecified industrial combustion	2,228	1,763	337	128	25	25	25	25	25	25	25	25	25
H	Cement manufacture	107	0	5	102	99	99	99	99	99	99	99	99	99
S	Lime manufacture	89	0	0	89	89	89	89	89	89	89	89	89	89
V	Nitric acid production	4	0	0	4	4	4	4	4	4	4	4	4	4
G	Ammonia manufacture and urea consumption	24	0	24	0	0	0	0	0	0	0	0	0	0
F	Aluminum production	0	0	0	0	0	0	0	0	0	0	0	0	0
E	Adipic acid production	4	0	4	0	0	0	0	0	0	0	0	0	0
I	Semiconductor manufacture	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	Soda ash manufacture and consumption	5	5	0	0	0	0	0	0	0	0	0	0	0
T	Magnesium production and processing	0	0	0	0	0	0	0	0	0	0	0	0	0
EE	Titanium dioxide production	8	8	0	0	0	0	0	0	0	0	0	0	0
K	Ferroalloy production	6	0	6	0	0	0	0	0	0	0	0	0	0
Z	Phosphoric acid production	14	0	0	14	14	14	14	14	14	14	14	14	14
GG	Zinc production	5	0	5	0	0	0	0	0	0	0	0	0	0
R	Lead production	0	0	0	0	0	0	0	0	0	0	0	0	0
BB	Silicon carbide production and consumption	1	1	0	0	0	0	0	0	0	0	0	0	0
N	Glass	1	0	1	0	0	0	0	0	0	0	0	0	0
C	Cogen	485	0	102	383	0	0	0	0	0	0	0	0	0
P	Hydrogen	30	0	30	0	0	0	0	0	0	0	0	0	0

Table 4-4. Subpart E Adipic Acid: Labor Costs (2006$)

	Labor Hours																Labor Cost per Year per Reporting Unit/Facility	
	Electricity Manager $88.79		Refinery Manager $101.31		Industrial Manager $71.03		Lawyer $101.00		Electricity Eng/Tech $60.84		Refinery Eng/Tech $63.89		Industrial Eng/Tech $55.20		Admin $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning					8	2	1	1					16	4	8		$1,790	$464
QA/QC													8	8	1	1	$494	$494
Recordkeeping													8	8	1	1	$494	$494
Sampling, analysis, and calculations					19	19							19	19			$2,335	$2,335
Reporting					4	4							24	24	9	9	$1,898	$1,898
Total					**32**	**26**	**1**	**1**					**75**	**63**	**18**	**10**	**$7,011**	**$5,685**

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-5. Subpart E Adipic Acid: Capital and O&M Costs (2006$)

Activity	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	Total Reporting per Unit/Facility Cost	
					First Year	Subseq. Year
Equipment (selection, purchase, installation)				$1,200	$1,200	$1,200
Performance testing				$117	$117	$117
Recordkeeping					$0	$0
Travel				$1,234	$1,234	$1,234
Total	**$0**		**$0**	**$2,551**	**$2,551**	**$2,551**

4.5 Subpart F—Aluminum Production

Overview. Aluminum production capacities at U.S. primary production facilities are generally comparable (low hundreds of thousands of metric tons). Costs were therefore developed for a single model facility based on reported average labor burdens and annualized average non-labor costs (Table 4-6 and Table 4-7).

Labor Costs. Total labor costs are $19,700; a majority of the costs are associated with sampling and analysis activities performed by an industrial engineer/technician ($17,700).

Capital and O&M Costs. There are no new capital equipment requirements for this subpart. Reporting requires approximately $600 of sampling O&M costs. These costs cover process emissions.

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) costs.

Table 4-6. Subpart F Aluminum Production: Labor Costs (2006$)

Activity	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility[a]	
	Legal $101.00		Managerial $71.03		Technical $55.20		Clerical $29.65			
	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year
Planning			1	1	1	1			$143	$143
QA/QC										
Recordkeeping										
Sampling and analysis (calculations)			65	65	238	238			$17,738	$17,738
Reporting			25	25			1	1	$1,795	$1,795
Total			**91**	**91**	**239**	**239**	**1**	**1**	**$19,676**	**$19,676**

[a] Assumes annual sampling; for more information, please refer to the cost appendix.

Table 4-7. Subpart F Aluminum Production: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs				$595	$595	$595
Total	**$0**		**$0**	**$595**	**$595**	**$595**

4.6 Subpart G—Ammonia Manufacturing

Baseline Reporting. We do not know how many ammonia manufacturing companies are estimating and reporting emissions at the facility level to meet internal GHG management programs or state or voluntary reporting programs at the domestic or international level. We are assuming that no ammonia manufacturing facilities are currently reporting emissions and that many of the proposed requirements will result in “new” or “full” costs to meet reporting requirements.

We are assuming that the proposed requirements will result in “full” costs primarily to meet EPA’s reporting requirements. Specifically, we assume that additional costs will be incurred for preparing monitoring and QA/QC plans, sampling and analysis of feedstock for carbon content, performing the calculations, reporting the results, and maintaining records. The only significant element of the approach that we know is performed routinely by all companies is that they have measurements and records of fuel and feedstock consumed as part of their routine operation for accounting purposes.

Overview. Insufficient data was available to differentiate costs for compiling data and conducting sampling across different facilities; hence, model facilities were not developed. Professional judgment was used to develop cost estimates and sampling frequency was assumed not to differ by facility size. The selected option requires continuous measurement of fuel; internal development of the methodology and monitoring plan for calculating emissions from production process; managers’ reviews of samples per sampling period; contacting supplier to get the carbon content of the reducing agent; and QA/QC of supplier information on carbon content of the reducing agent.

Labor Costs. Total labor costs are $3,300 in the first year and $2,100 in subsequent years; a majority of the labor costs are associated with sampling and analysis activities performed by an industrial engineer/technician (approximately $2,400 in the first year and $1,300 in subsequent years).

Capital and O&M Costs. There are no new capital equipment requirements for this subpart. Reporting requires approximately $800 of sampling O&M costs.

Table 4-8. Subpart G Ammonia: Labor Costs (2006$)

Activity	Lawyer $101.00 First Year	Lawyer $101.00 Subseq. Year	Industrial Manager $71.03 First Year	Industrial Manager $71.03 Subseq. Year	Industrial Engineer/ Technician $55.20 First Year	Industrial Engineer/ Technician $55.20 Subseq. Year	Administrative Support $29.65 First Year	Administrative Support $29.65 Subseq. Year	Labor Cost per Year per Reporting Unit/Facility First Year	Labor Cost per Year per Reporting Unit/Facility Subseq. Year
Planning										
QA/QC[a]					16	16			$883	$883
Recordkeeping										
Sampling and analysis[b]	1	1	16	10	21	8			$2,397	$1,253
Reporting										
Total	**1**	**1**	**16**	**10**	**37**	**24**			**$3,280**	**$2,136**

[a] Engineer collects composite samples of inputs and sends it to vendor for chemical analysis to verify supplier.

[b] Assumes four sampling events per year; for more information, please refer to the cost appendix.

Table 4-9. Subpart G Ammonia: Capital and O&M (2006$)

Activity	Cost Categories: Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	Total Reporting Cost per Unit/Facility: First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs[a]				$800	$800	$800
Total	**$0**		**$0**	**$800**	**$800**	**$800**

[a] Refers to quarterly sampling of carbon contents.

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

4.7 Subpart H—Cement Production

Baseline Reporting. Under voluntary domestic initiatives (such as EPA's Climate Leaders and DOE's Climate Vision, DOE's 1605b), some facilities are reporting emissions source categories. The analysis is based on the understanding that cement facilities perform daily sampling and LCA of their raw materials to determine carbonate and organic carbon contents, as part of their normal business operations.

Overview. Insufficient data was available to differentiate costs for compiling data and conducting sampling across different facilities; hence, model facilities were not developed. Professional judgment was used to develop cost estimates and sampling frequency was assumed not to differ by facility size. If continuous emission monitoring systems (CEMS) are available, direct measurement of combustion-related and process-related CO_2 emissions from cement kilns using CEMS is used. If CEMS are not available, facility-specific non-CEMS-based emissions estimates are to be developed using the mass-balance approach based on facility-specific analysis of carbonate and non-carbonate contents of clinker produced and raw material consumption and CKD usage and disposal.

Labor Costs. Total labor costs are $6,700 in the first year and $5,100 in subsequent years; a majority of the labor costs are associated with sampling and analysis activities performed by an industrial engineer/technician (approximately $5,200 in the first year and $4,700 in subsequent years).

Capital and O&M Costs. There are no new capital equipment requirements for this subpart. There is $300 in O&M sampling costs and reporting requires approximately $2,200 for contractor costs for software development and maintenance costs.

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-10. Subpart H Cement Manufacturing: Labor Costs (2006$)[a]

Activity	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility	
	Lawyer $101.00		Industrial Manager $71.03		Industrial Engineer/ Technician $55.20		Administrative Support $29.65			
	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year
Planning[b]	1	1	8	2	16	4			$1,552	$464
QA/QC										
Recordkeeping										
Sampling and analysis			14	16	76	64			$5,189	$4,669
Material sampling[c]			2	2	36	24			$2,129	$1,467
Emissions calculation[d]			12	14	40	40			$3,060	$3,202
Reporting									$0	$0
Total	**1**	**1**	**22**	**18**	**92**	**68**			**$6,742**	**$5,133**

[a] These costs correspond to incremental costs of monitoring emissions using non-CEMS method, via sampling. These costs are applicable only for the cement plants that do not have NO_x or CO_2 CEMS. Eighty-two plants were identified to have no CEMS installed on their kilns.

[b] Corresponds to internally developing the methodology and monitoring plan for calculating emissions from the production process.

[c] Includes incremental sampling costs, including manger's review. The costs correspond to a laboratory chemical analysis of nonfuel raw material inputs—carbonate and total organic carbon contents of 6 inputs, on average (the number of nonfuel raw material inputs used in cement facilities is in the range of 2 to 10).

[d] Includes costs of developing emissions calculations, based on raw material-specific carbon and carbonate measurements, raw material consumption data, and facility-specific CKD contents of fuels developed through chemical analysis or other methods approved by EPA. Also includes the costs of calculating CH_4 and N_2O emissions using emissions factors, if directed by EPA, and performing QA/QC of GHG emission calculations. Includes the incremental costs for regular monitoring of total quantity of all nonfuel raw material inputs (will vary by the type and number of raw materials to be measured and the monitoring method) and cement kiln dust, including QA/QCing and assembling data, as well. Plants do this activity as part of normal business operations and incremental costs reflect additional procedures that they need to put in place to standardize the process for regulatory data verification and onsite auditing.

Table 4-11. Subpart H Cement Manufacturing: Capital and O&M Costs (2006$)[a]

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)[b]						
Performance testing						
Recordkeeping						
Travel						
Sampling costs[c]				$300	$300	$300
Calculations[d]				$2,200	$2,200	$2,200
Total	**$0**		**$0**	**$300**	**$2,500**	**$2,500**

[a] These costs correspond to incremental costs of monitoring emissions using non-CEMS method, via sampling. These costs are applicable only for the cement plants that do not have NO_x or CO_2 CEMS. Eighty-two plants were identified to have no CEMS installed on their kilns.

[b] It was assumed that cement plants could use their existing equipment and that no additional equipment purchase was necessary for the non-CEMS method of monitoring emissions.

[c] The O&M costs correspond to the incremental costs of maintaining the existing onsite testing facilities and software needed for documenting the biweekly sampling results, needed for emission calculations.

[d] O&M costs represent contractor costs for software development and maintenance costs.

4.8 Subpart I—Electronics Manufacturing

Overview. This analysis is based on the costs of monitoring fluorinated GHG emissions from semiconductor manufacturing facilities. Semiconductor facilities constitute the vast majority of the electronics facilities likely to report under the rule, and EPA has acquired a detailed understanding of semiconductor facilities and their emissions through the PFC Reduction/Climate Partnership for Semiconductors, which has been in place since 1995.

In the proposed rule, semiconductor facilities with production capacities of 10,500 m^2 silicon or greater are considered “large” facilities and those with production capacities less than 10,500 m^2 silicon are considered “small” facilities. “Small” and “large” facilities are subject to different reporting requirements, as detailed below under “Monitoring Costs.” These differences lead to different annual costs for “small” and “large” semiconductor facilities.

Other electronics manufacturing facilities (MEMs, Flat Panel Display, Photovoltaics) use fewer types of PFCs than the semiconductor manufacturing facilities. Therefore, cost estimates for these other types of electronics facilities were developed by scaling the costs for the small semiconductor facilities to account for the use of a smaller set of gases.

Labor Costs. Total labor costs are $14,200 in the first year and subsequent years; a majority of the labor costs are associated with sampling and analysis activities performed by an industrial engineer/technician (approximately $11,300 in the first and subsequent years).

Capital and O&M Costs. There are no new capital equipment requirements for this subpart. Reporting requires approximately $14,200 of sampling O&M costs.

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) costs.

Table 4-12. Subpart I Electronics: Labor Costs (2006$)

	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility[a]	
	Legal $101.00		Managerial $71.03		Technical $55.20		Clerical $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning										
QA/QC										
Recordkeeping										
Sampling and analysis (calculations)			22	22	169	169	14	14	$11,327	$11,327
Reporting	0.3	0.3	14	14	28	28	10	10	$2,869	$2,869
Total	**0.3**	**0.3**	**36**	**36**	**197**	**197**	**24**	**24**	**$14,196**	**$14,196**

[a] Assumes annual sampling; for more information, please refer to the cost appendix.

Table 4-13. Subpart I Electronics: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs[a]	**$0**		**$0**	**$14,225**	**$14,225**	**$14,225**

[a] Refers to in-fab DRE measurements.

4.9 Subpart J—Ethanol Production

For this source category, EPA evaluated ethanol refinery wastewater treatment plants to represent the types of wastewater treatment systems with the greatest potential to exceed the GHG threshold. See Subpart II Wastewater for additional cost details

Stationary Combustion Costs. This subpart is not assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-14. Subpart J Ethanol: Labor Costs (2006$)

Activity	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility	
	Lawyer $101.00		Industrial Manager $71.03		Industrial Engineer/ Technician $55.20		Administrative Support $29.65			
	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year
Planning										
QA/QC	Wastewater costs only; see Subpart II Wastewater									
Recordkeeping										
Sampling and analysis										
Reporting										
Total										

Table 4-15. Subpart J Ethanol: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing	Wastewater costs only; See Subpart II Wastewater					
Recordkeeping						
Travel						
Sampling costs						
Total						

4.10 Subpart K—Ferroalloy Production

Baseline Reporting. Under voluntary domestic initiatives (such as EPA's Climate Leaders and DOE's Climate Vision, DOE's 1605b), some facilities are reporting emissions source categories. The analysis assumes that facilities have measurements and records of consumption of raw materials such as reducing agents as part of their routine operations and for accounting purposes.

Overview. Insufficient data was available to differentiate costs for compiling data and conducting sampling across different facilities; hence, model facilities were not developed. Professional judgment was used to develop cost estimates and sampling frequency was assumed not to differ by facility size. Reporting requires annual carbon balance using monthly off-site sampling by facilities to determine carbon content of each carbonaceous input.

Labor Costs. Total labor costs are $9,600 in the first year and $8,000 in subsequent years; a majority of the labor costs are associated with sampling and analysis activities performed by an industrial engineer/technician ($8,100 in the first year and $7,500 in subsequent years).

Capital and O&M Costs. There are no new capital equipment requirements for this subpart. Reporting requires approximately $12,000 of sampling O&M costs.

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-16. Subpart K Ferroalloy Production: Labor Costs (2006$)

Activity	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility	
	Lawyer $101.00		Industrial Manager $71.03		Industrial Engineer/ Technician $55.20		Administrative Support $29.65			
	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year
Planning	1	1	8	2	16	4			$1,552	$464
QA/QC										
Recordkeeping										
Sampling and analysis[a]					130	120	30	30	$8,065	$7,513
Reporting										
Total	**1**	**1**	**8**	**2**	**146**	**124**	**30**	**30**	**$9,617**	**$7,977**

[a] Refers to monthly sampling of carbon contents for five inputs including coal, coke, electrode paste, prebaked electrodes, and petroleum coke. For more information, please refer to the cost appendix.

Table 4-17. Subpart K Ferroalloy Production: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs[a]				$12,000	$12,000	$12,000
Total	**$0**		**$0**	**$12,000**	**$12,000**	**$12,000**

[a] Refers to monthly sampling of carbon contents for five inputs including coal, coke, electrode paste, prebaked electrodes, and petroleum coke; for more information, please refer to the cost appendix.

4.11 Subpart L–Fluorinated Gas Production

Baseline Reporting. Under voluntary domestic initiatives (such as EPA's Climate Leaders and DOE's Climate Vision, DOE's 1605b), some facilities are reporting emissions source categories.

Overview. The model fluorinated GHG production facility is one that produces fluorinated GHGs, including hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), and a number of fluorinated ethers. Fluorinated GHGs can escape during the production process. Emissions can occur from leaks at flanges and connections in the production line, from byproduct streams that are imperfectly separated from the main product stream, and during the filling of tanks or other containers to be shipped on trucks and railcars. These are considered fugitive emissions from the production process. For the purposes of estimating costs, the single model is a facility that produces fluorinated GHGs.

Fugitive emissions are calculated using a mass-balance or yield approach. In this approach, emissions are equated to the difference between the expected production of each fluorinated GHG based on the consumption of reactants and the measured production of that fluorinated GHG, accounting for yield losses related to byproducts and wastes.

Under the proposed rule, owners or operators would be required to use scales and/or flow meters with an accuracy of 0.2% of full scale to measure reactants, products, byproducts and wastes. In addition, they would be required to perform daily mass balance calculations for each product produced. In this calculation, they would be required to account for any product that was inadvertently mixed into the byproducts or wastes using equipment and methods (e.g., gas chromatography) with an accuracy of 5 percent or better at the concentrations of the process samples.

Labor Costs. Reporting requires 4 hours of labor at a cost of $237.

Capital and O&M Costs. There are no new capital equipment or O&M requirements for this subpart.

Stationary Combustion Costs. This subpart is not assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-18. Subpart L Fluorinated GHG Production: Labor Costs (2006$)

Activity	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility[a]	
	Legal $101.00		Managerial $71.03		Technical $55.20		Clerical $29.65			
	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year
Planning										
QA/QC										
Recordkeeping										
Sampling and analysis (calculations)			1	1	3	3			$237	$237
Reporting										
Total			**1**	**1**	**3**	**3**			**$237**	**$237**

[a] Assumes annual sampling; for more information, please refer to the cost appendix.

Table 4-19. Subpart L Fluorinated GHG Production: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs						
Total	**$0**		**$0**	**$0**	**$0**	**$0**

4.12 Subpart M—Food Processing

Overview. For this source category, EPA evaluated food processing wastewater treatment plants, including meat processors, poultry processors, and fruit/vegetable processors to represent the types of wastewater treatment systems with the greatest potential to exceed the GHG threshold. See subpart II Wastewater and subpart HH for additional cost details.

Stationary Combustion Costs. This subpart is not assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-20. Subpart M Food Processing: Labor Costs (2006$)

Activity	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility	
	Lawyer $101.00		Industrial Manager $71.03		Industrial Engineer/ Technician $55.20		Administrative Support $29.65			
	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year
Planning										
QA/QC	Wastewater and landfill costs only; see Subpart II Wastewater and Subpart HH Landfills									
Recordkeeping										
Sampling and analysis										
Reporting										
Total										

Table 4-21. Subpart M Food Processing: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing	Wastewater and landfill costs only; see Subpart II Wastewater and Subpart HH Landfills					
Recordkeeping						
Travel						
Sampling costs						
Total						

4.13 Subpart N—Glass Production

Baseline Reporting. For glass production, we are not sure how many companies are currently estimating and reporting emissions at the facility level to meet internal GHG management programs or state or voluntary reporting programs at the domestic or international level. Therefore, we are assuming that no glass production facilities are currently reporting emissions and that many of the proposed requirements will result in "new" or "additional" costs to meet reporting requirements.

However, many glass production facilities are currently tracking much of the data required to estimate process-related CO_2 emissions on a routine basis (carbonate inputs, supplier information on carbonate composition of inputs). We are assuming that the proposed requirements will result in "additional" costs primarily to meet EPA's reporting requirements. For example, we assume that additional costs incurred will be for preparing monitoring and QA/QC plans, performing the calculations, reporting the results, and maintaining records (essentially developing a monitoring plan, reporting, recordkeeping, and QA/QC).

Overview. Insufficient data was available to differentiate costs for compiling data and conducting sampling across different facilities; hence, model facilities were not developed. Professional judgment was used to develop cost estimates and sampling frequency was assumed not to differ by facility size. Reporting requires monthly onsite measurements of the weight fraction of carbonate inputs (i.e., calcite, dolomite, and sodium carbonate) and calcination fractions. This method uses IPCC default emission factors.

Labor Costs. Reporting requires 25 hours of labor at a cost of $1,500 in the first year. In subsequent years, 7 hours are required at a cost of $464.

Capital and O&M Costs. There are no new capital equipment or O&M requirements for this subpart.

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-22. Subpart N Glass: Labor Costs (2006$)

Activity	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility	
	Lawyer $101.00		Industrial Manager $71.03		Industrial Engineer/ Technician $55.20		Administrative Support $29.65			
	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year
Planning	1	1	8	2	16	4			$1,552	$464
QA/QC										
Recordkeeping										
Sampling and analysis										
Reporting										
Total	**1**	**1**	**8**	**2**	**16**	**4**			**$1,552**	**$464**

Table 4-23. Subpart N Glass: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs						
Total	**$0**		**$0**	**$0**	**$0**	**$0**

4.14 Subpart O—HCFC-22 Production

Overview. Three HCFC-22 production facilities operated in the United States in 2006. For the purpose of estimating costs, a model facility was developed by taking the average of facility-specific cost estimates; the facility-specific cost estimates vary primarily depending on the process architecture of each facility. Hence, the model facility is an average facility that incurs the average of costs across all facilities.

Labor Costs. Total labor costs are $5,600 in the first year and subsequent years; a majority of the labor costs are associated with sampling and analysis activities.

Capital and O&M Costs. There are no new capital equipment or O&M requirements for this subpart.

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-24. Subpart O HCFC-22 Production: Labor Costs (2006$)

	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility[a]	
	Legal $101.00		Managerial $71.03		Technical $55.20		Clerical $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning										
QA/QC										
Recordkeeping										
Sampling and analysis (calculations)			2	2	85	85	25	25	$5,599	$5,599
Reporting										
Total			**2**	**2**	**85**	**85**	**25**	**25**	**$5,599**	**$5,599**

[a] Sampling frequency varies by plant; for more information, please refer to the cost appendix.

Table 4-25. Subpart O HCFC-22 Production: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs						
Total	**$0**		**$0**	**$0**	**$0**	**$0**

4.15 Subpart P—Hydrogen Production

Overview. The estimated 77 merchant hydrogen production facilities in the United States range in capacity from around 6 to almost 200,000 metric tons of hydrogen per year. Even so, the same amount of data are collected for each facility, and therefore the monitoring cost for each site is the same. The feedstock mass balance cost data are calculated for merchant hydrogen production facilities using natural gas, other hydrocarbon gases and liquids, and solid fuels (coal, pet coke) as feedstock. For this analysis, there is no distinction in the feedstock mass balance cost data for the various feedstock materials.

The monitoring approach is a hybrid method which combines direct measurement by CEMS, where CEMS components are currently employed for other purposes, and the fuel and feedstock mass balance approach at facilities where CEMS are not currently employed or at facilities where combustion or process CO_2 emissions are emitted via secondary stacks or vents. CEMS-method facilities will have CO_2 monitoring in place and will retrofit CEMS by installing a stack flow meter. CEMS costs have been addressed under Stationary Combustion in the RIA, consequently, this cost analysis is focused on only those facilities that will use the fuel and feedstock mass balance approach.

Labor Costs. Total labor costs are $3,100 in the first year and $1,500 in subsequent years; a majority of the labor costs are associated with planning and sampling and analysis activities (including manager’s review).

Capital and O&M Costs. There are no new capital equipment requirements for this subpart. Reporting requires approximately $200 of sampling O&M costs.

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-26. Subpart P Hydrogen Production: Labor Costs (2006$)

	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility	
	Lawyer $101.00		Industrial Manager $71.03		Industrial Engineer/ Technician $55.20		Administrative Support $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning[a]	1	1	8	2	16	4			$1,552	$464
QA/QC[b]					11	4			$607	$221
Recordkeeping									$0	$0
Sampling and analysis (calculations)[c]					7	4			$386	$221
Manager's review[d]			8	8					$568	$568
Reporting									$0	$0
Total	**1**	**1**	**16**	**10**	**34**	**12**			**$3,114**	**$1,474**

[a] Internally develop the methodology and monitoring plan for calculating emissions from production process per facility—first year is developing plan; subsequent years are reviewing and updating plan.

[b] QA/QC suppliers information on C content.

[c] Assumes one QA/QC sampling event per year.

[d] Manager’s review of samples per sampling period per facility per sampling period.

Table 4-27. Subpart P Hydrogen Production: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs[a]				$200	$200	$200
Total	**$0**		**$0**	**$200**	**$200**	**$200**

[a] Refers to annual QA/QC sampling of carbon content to check supplier data.

4.16 Subpart Q—Iron and Steel Production

Baseline Reporting. Through voluntary domestic initiatives (such as DOE's Climate Vision), the U.S. iron and steel industry as a sector has undertaken voluntary efforts to develop a simple protocol (based on default emission factors), educate association members, and track emission intensity of production (more information is available at: http://www.climatevision.gov/sectors/steel/index.html).

Several iron and steel companies in the United States and abroad have recommended and are using a carbon balance approach similar to the proposed method. Based on private communications with steel industry representatives and general knowledge of plant operations, it is recognized that many of the measurements required for that approach, such as the amount of specific feedstocks consumed, production rates from each process, process gas (coke oven gas, blast furnace gas) production and consumption, and purchased fuel consumption, are already routinely measured and used for accounting purposes (e.g., determining the cost of production), process control, and yield calculations. For example, U.S. steel plants report many of these measurements to the American Iron and Steel Institute (AISI), and AISI compiles annual nationwide statistics from the reported information (e.g., see http://www.steel.org/AM/ Template.cfm?Section=Statistics). Consequently, the proposed approach offers an advantage in that it would use a significant amount of information that is already readily available to companies and their facilities.

However, it is not clear how many companies are currently implementing this approach at the facility level to meet internal GHG management programs or state or voluntary reporting programs at the domestic or international level. Therefore, we are assuming that iron and steel production facilities are not currently reporting emissions and that many of the proposed requirements will result in “new” or “additional” costs to meet reporting requirements. For example, we assume that additional costs will be incurred for preparing monitoring and QA/QC plans, sampling and analysis of process inputs and outputs for carbon content, performing the calculations, reporting the results, and maintaining records. The only significant element of the approach that we know is performed routinely by all companies is that they have measurements and records of process inputs and outputs as part of their routine operation.

Labor Costs. The labor costs are associated with all activities are $146,000 in the first year and $112,000 in subsequent years.

Capital and O&M Costs. There are no new capital equipment requirements for this subpart. Annualized performance testing costs are estimated to be $2,400.

Stationary Combustion Costs. This subpart is not assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-28. Subpart Q Iron & Steel: Labor Costs (2006$)

Subpart Q—Iron and Steel Industry-Combustion & Process	Labor Hours																Labor Cost per Year per Reporting Unit/Facility	
	Electricity Manager $88.79		Refinery Manager $101.31		Industrial Manager $71.03		Lawyer $101.00		Electricity Eng/Tech $60.84		Refinery Eng/Tech $63.89		Industrial Eng/Tech $55.20		Admin $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning					24						477				48		$33,561	$0
QA/QC					19	19					376	376			38	38	$26,451	$26,451
Recordkeeping					19	19					376	376			38	38	$26,451	$26,451
Sampling, analysis, and calculations													595	595			$32,855	$32,855
Reporting					19	19					376	376			38	38	$26,451	$26,451
Total					**80**	**56**	**0**	**0**	**0**	**0**	**1,604**	**1,127**	**595**	**595**	**160**	**113**	**$145,770**	**$112,209**

Table 4-29. Subpart Q Iron & Steel: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing			$2,400		$2,400	$2,400
Recordkeeping						
Travel						
Total	**$0**		**$2,400**	**$0**	**$2,400**	**$2,400**

4.17 Subpart R—Lead Production

Baseline Reporting. Under voluntary domestic initiatives (such as EPA's Climate Leaders and DOE's Climate Vision, DOE's 1605b), some facilities are reporting emissions source categories. The analysis assumes that facilities have measurements and records of consumption of raw materials such as reducing agents as part of their routine operations and for accounting purposes.

Overview. Insufficient data was available to differentiate costs for compiling data and conducting sampling across different facilities; hence, model facilities were not developed. Professional judgment was used to develop cost estimates and sampling frequency was assumed not to differ by facility size. Reporting requires Annual carbon balance using monthly measurement of the carbon content of up to three reductants (e.g., metallurgical coke) sent off-site for lab sampling.

Labor Costs. Total labor costs are $6,400 in the first year and $5,000 in subsequent years; a majority of the labor costs are associated with planning ($1,600) and sampling and analysis activities ($4,800). Planning costs fall to $500 and sampling and analysis activities fall to $4,500 in subsequent years.

Capital and O&M Costs. There are no new capital equipment requirements for this subpart. Reporting requires approximately $7,200 of sampling O&M costs.

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-30. Subpart R Lead: Labor Costs (2006$)

	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility	
	Lawyer $101.00		Industrial Manager $71.03		Industrial Engineer/ Technician $55.20		Administrative Support $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning	1	1	8	2	16	4			$1,552	$464
QA/QC									$0	$0
Recordkeeping									$0	$0
Sampling and analysis[a]					78	72	18	18	$4,839	$4,508
Reporting									$0	$0
Total	**1**	**1**	**8**	**2**	**94**	**76**	**18**	**18**	**$6,391**	**$4,972**

[a] Assumes 12 sampling events per year for three inputs (metallurgical coke, petroleum coke, carbon electrode). For more information, please refer to the cost appendix.

Table 4-31. Subpart R Lead: Capital and O&M Costs (2006$)

	Cost Categories				Total Reporting Cost per Unit/Facility	
Activity	**Capital Cost**	**Equipment Lifetime (years)**	**Annualized Capital Cost (per year)**	**O&M Costs (per year)**	**First Year**	**Subseq. Year**
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs[a]				$7,200	$7,200	$7,200
Total	**$0**		**$0**	**$7,200**	**$7,200**	**$7,200**

[a] Refers to monthly sampling of carbon contents (metallurgical coke, petroleum coke, and carbon electrode). For more information, please refer to the cost appendix.

4.18 Subpart S—Lime Manufacturing

Baseline Reporting. Under voluntary domestic initiatives (such DOE's Climate Vision, DOE's 1605b), the National Lime Association (NLA), which represents 95% of the domestic commercial lime production sector, has undertaken voluntary efforts to develop a GHG emissions protocol (based on facility specific information), educate association members, and track emissions intensity of production (more information is available at: http://www.climatevision.gov/sectors/lime/index.html).

NLA members have recommended and are using the NLA method. For example, U.S. lime manufacturing facilities report many of these measurements to NLA, and NLA compiles annual nationwide statistics from the reported information. Consequently, the proposed approach offers an advantage in that it would use a significant amount of information that is already readily available to companies and their facilities.

Given that NLA represents a significant number of lime producers and a significant amount of domestic lime production, we are assuming that lime production facilities are currently collecting the data to report process related CO_2 emissions at the facility level (monthly lime production, CaO and MgO content of lime products, calcinations of byproducts). We are assuming that the proposed requirements will result in "additional" costs primarily to meet EPA's reporting requirements. For example, we assume that additional costs incurred will be for preparing monitoring and QA/QC plans, performing the calculations, reporting the results, and maintaining records (essentially developing a monitoring plan, reporting, recordkeeping, and QA/QC).

Overview. Insufficient data was available to differentiate costs for compiling data and conducting sampling across different facilities; hence, model facilities were not developed. Professional judgment was used to develop cost estimates and sampling frequency was assumed not to differ by facility size.

Labor Costs. The labor costs are associated with planning are $1,600 in the first year and subsequent years.

Capital and O&M Costs. There are no new capital equipment and O&M requirements for this subpart.

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-32. Subpart S Lime Manufacturing: Labor Costs (2006$)

	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility	
	Lawyer $101.00		Industrial Manager $71.03		Industrial Engineer/ Technician $55.20		Administrative Support $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning	1	1	8	2	16	4			$1,552	$464
QA/QC										
Recordkeeping										
Sampling and analysis										
Reporting										
Total	**1**	**1**	**8**	**2**	**16**	**4**			**$1,552**	**$464**

Table 4-33. Subpart S Lime Manufacturing: Capital and O&M Costs (2006$)

	Cost Categories				Total Reporting Cost per Unit/Facility	
Activity	**Capital Cost**	**Equipment Lifetime (years)**	**Annualized Capital Cost (per year)**	**O&M Costs (per year)**	**First Year**	**Subseq. Year**
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs						
Total	**$0**		**$0**	**$0**	**$0**	**$0**

4.19 Subpart T—Magnesium Production

Overview. Costs for estimating GHG emissions from magnesium production and processing facilities were estimated for emissions of SF_6 and other cover gases. Estimating SF_6 and other cover gas GHG emissions requires facility-specific data on cover gas consumption. The primary cover gas of concern is SF_6, with replacement compounds such as HFC-134a also being tracked when utilized. The methodology for which cost estimates were developed is based upon a simple estimate of cover gas consumption by facility.

Labor Costs. Total labor costs are $2,700 in the first year and subsequent years; a majority of the labor costs are associated with sampling and analysis ($1,900) and reporting activities ($700).

Capital and O&M Costs. There are no new capital equipment requirements for this subpart. Reporting requires approximately $150 of reporting and sampling O&M costs. The costs are associated with process emissions.

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-34. Subpart T Magnesium Production: Labor Costs (2006$)

	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility[a]	
	Legal $101.00		Managerial $71.03		Technical $55.20		Clerical $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning										
QA/QC										
Recordkeeping							4	4	$119	$119
Sampling and analysis (calculations)			5	5	28	28			$1,873	$1,873
Reporting	2	2	2	2	6	6			$675	$675
Total	**2**	**2**	**7**	**7**	**34**	**34**	**4**	**4**	**$2,667**	**$2,667**

[a] Assumes annual sampling; for more information, please refer to the cost appendix.

Table 4-35. Subpart T Magnesium Production: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel				$117	$117	$117
Sampling costs				$36	$36	$36
Total	**$0**		**$0**	**$153**	**$153**	**$153**

4.20 Subpart V—Nitric Acid Production

Overview. Costs were developed for the following proposed monitoring option for estimating N_2O emissions from nitric acid production. The proposed option is to follow the Tier 3 approach established by IPCC using non-continuous monitoring: directly monitor N_2O emissions and determine the relationship between nitric acid production and the amount of N_2O emissions (i.e., develop a site-specific emissions factor). The site-specific emissions factor and production rate (activity level) is used to calculate the emissions. Annual testing of N_2O emissions would also be required to verify the emission factor over time. Testing would also be required whenever significant process changes are made.

This option uses non-continuous direct monitoring of N_2O emissions to determine the relationship between nitric acid production and the amount of N_2O emissions. As the production rate changes, a new N_2O emission rate could be calculated. Annual testing of N_2O emissions would also be required to verify the emission factor over time. Testing would also be required whenever significant process changes are made.

The proposed monitoring method for calculating process emissions from nitric acid production would involve this facility-level calculation on a monthly basis and stack testing on an annual basis. Each facility needs to internally develop the methodology and monitoring plan for calculating the process emissions from the nitric acid production process.

Labor Costs. Total labor costs are $8,800 in the first year and $7,700 in subsequent years; a majority are associated with planning, sampling and analysis, and reporting activities.

Capital and O&M Costs. There are no new capital equipment requirements for this subpart. Reporting requires performance testing, recordkeeping and travel (approximately $3,800).

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-36. Subpart V Nitric Acid: Labor Costs (2006$)

	Labor Hours																Labor Cost per Year per Reporting Unit/Facility	
	Electricity Manager $88.79		Refinery Manager $101.31		Industrial Manager $71.03		Lawyer $101.00		Electricity Eng/Tech $60.84		Refinery Eng/Tech $63.89		Industrial Eng/Tech $55.20		Admin $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning					8	2	1	1					16	4			$1,552	$464
QA/QC																	$0	$0
Recordkeeping																	$0	$0
Sampling, analysis, and calculations					38	38							50	50			$5,469	$5,460
Reporting					12	12							12	12	12	12	$1,801	$1,801
Total					**58**	**52**	**1**	**1**					**77**	**65**	**12**	**12**	**$8,822**	**$7,725**

Table 4-37. Subpart V Nitric Acid: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing				$3,466	$3,466	$3,466
Recordkeeping				$72	$72	$72
Travel				$231	$231	$231
Total	**$0**		**$0**	**$3,769**	**$3,769**	**$3,769**

4.21 Subpart W—Oil and Natural Gas Systems

Overview. For each of the industry segments, operations had to be divided into single units or model facilities at three levels; "small," "medium," and "large." The monitoring costs were then developed per size level of a model facility. A model facility of a given level can be defined as the most convenient and logical unit with appropriate emissions source counts that can aggregate to any size company to determine its monitoring costs. For example, in onshore natural gas transmission, a compressor station as a facility was modeled at the different levels. Any transmission company can determine its monitoring costs by assigning model facility costs to its facilities that are closest to the appropriate level of the model facility.

For each of the sources designated for monitoring, both equipment and component counts were determined to define individual model facilities. For onshore natural gas processing, onshore natural gas transmission, underground natural gas storage, and LNG storage and import facilities, emissions source counts for medium facilities were assigned the national average activity factors from the National Inventory. The related uncertainty in those activity factors were used to determine the lower bound on emissions source counts, and assigned to a "small" facility. Similarly, the upper bound on emissions source counts was assigned to a "large" facility. In the case of offshore petroleum and natural gas production, MMS GOADS-2000 data analysis by EPA was used in the same fashion as the national inventories. In some cases, the uncertainty estimates were not applicable. For example, if the uncertainty is over 100%, it would predict a negative lower bound for emissions source counts. For these cases, expert judgment was used. Expert judgment was also used, where necessary, to adjust emissions source counts to reflect real world scenarios.

Labor Costs. To evaluate labor costs, it was necessary not only to determine the amount of time required for all of the tasks associated with monitoring, but also to determine who will perform each task. For the sake of this analysis, four labor categories were used. Assigning labor hours for all cost elements was based on expert judgment. When assigning hours, the size of the facility and role of the labor categories were taken into consideration.

Capital and O&M Costs. The labor costs associated with performing the actual annual monitoring were omitted from the table above. For these costs it was assumed that all labor will be performed by middle managers, junior engineers, and senior operators. Middle managers will spend a total of 2 hours overseeing the monitoring process per quarter, but will not perform any of the monitoring. It was assumed that junior engineers will do all of the monitoring, except in cases where senior operators will log any activity data required to estimate emissions over the course of the quarter. Several equipment types are common between different onshore segments and different facility sizes, but the actual monitoring time will not change per equipment unit. For example, reciprocating compressors are found in all onshore segments for facilities of almost all sizes. Screening a single reciprocating compressor for leaks was assumed to take 2 hours onshore, and that will not change by segment or facility size. What changes is the number of reciprocating compressors. Thus, a series of universal assumptions about onshore monitoring times were created. These were multiplied by the emissions source counts assigned to each of the model facilities to determine the required labor hours. Once the labor hours were calculated, by category, for each of the cost elements, they were multiplied by the associated labor rates to estimate labor costs per facility. The only remaining facility costs are due to the annualized capital costs and travel, lodging, and shipping to conduct the actual emissions monitoring.

The capital costs related to monitoring emissions and archiving of information consists of purchasing equipment for emissions detection, emissions measurement, and information storage. All costs are reported in 2006 U.S. dollars and annualization was assumed over an equipment life of 5 years with a 7% interest rate.

Stationary Combustion Costs. This subpart is not assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-38. Subpart W Oil and Natural Gas Systems: Labor Costs (2006$)

	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility	
	Senior Management ($101.31/hr)		Middle Management ($88.79/hr)		Junior Engineer ($71.03/hr)		Senior Operator ($63.89/hr)			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning	1.67	0.09	7.46	0.31	30.84	1.33	16.23	0.64	$4,059	$173
QA/QC										
Recordkeeping	0.42	0.45	0.65	0.71	4.17	4.92	1.05	1.25	$464	$538
Sampling and analysis (calculations)			3.65	3.65	72.12	79.10	4.20	4.20	$5,715	$6,211
Reporting	0.12	0.13	3.17	3.34	5.14	5.85	13.81	16.30	$1,540	$1,766
Total	**1.20**	**0.53**	**11.14**	**7.73**	**62.04**	**47.36**	**19.12**	**11.40**	**$11,777**	**$8,687**

Table 4-39. Subpart W Oil and Natural Gas Systems: Capital and O&M Costs (2006$)

	Cost Categories				Total Reporting Cost per Unit/Facility	
Activity	**Capital Cost**	**Equipment Lifetime (years)**	**Annualized Capital Cost (per year)**	**O&M Costs (per year)**	**First Year**	**Subseq. Year**
Equipment (selection, purchase, installation)	$27,414	5	$6,686		$6,686	$6,686
Performance testing						
Recordkeeping	$94	5	$23		$23	$23
Travel				$2,929	$2,929	$2,929
Total	**$27,508**		**$6,709**	**$2,929**	**$9,638**	**$9,638**

4.22 Subpart X—Petrochemical Production

Overview. Each petrochemical production facility would measure the flow rate and carbon content (or composition) of each feedstock and each product. Flow rates would be measured continuously, and carbon content would be measured at least once per week. The difference in the carbon content between the feedstocks and the products would provide an estimate of the process-based CO_2 emissions. Facilities would also measure the flow and carbon content of supplemental fuel used in combustion units that supply energy to the petrochemical process at the recommended frequency for stationary fuel combustion sources. For this analysis, natural gas was assumed to be the supplemental fuel, which means the flow would be measured continuously, and the carbon content would be measured once per month. This information would be used in the applicable equations for stationary fuel combustion sources to estimate the CO_2, CH_4, and N_2O emissions from combustion sources associated with petrochemical processes.

Labor Costs. Total labor costs are $14,800 in the first year and $10,800 in subsequent years; a majority of the labor costs are associated with quality assurance and control checks, recordkeeping, and planning activities.

Capital and O&M Costs. There are no new capital equipment requirements for this subpart. Equipment O&M costs approximately $1,800 per year and performance testing requires approximately $1,900 per year.

Stationary Combustion Costs. This subpart is not assigned additional stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use costs only.

Table 4-40. Subpart X Petrochemical Production: Labor Costs (2006$)

Activity	Labor Hours																Labor Cost per Year per Reporting Unit/Facility	
	Electricity Manager $88.79		Refinery Manager $101.31		Industrial Manager $71.03		Lawyer $101.00		Electricity Eng/Tech $60.84		Refinery Eng/Tech $63.89		Industrial Eng/Tech $55.20		Admin $29.65			
	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year
Planning			5										44	38			$2,924	$2,087
QA/QC													132	74			$7,291	$4,100
Recordkeeping													59	59			$3,246	$3,246
Sampling, analysis, and calculations													12	12			$662	$662
Reporting			7	7													$669	$669
Total			**12**	**7**									**247**	**183**	**0**	**0**	**$14,792**	**$10,764**

Table 4-41. Subpart X Petrochemical Production: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)				$1,800	$1,800	$1,800
Performance testing				$1,984	$1,984	$1,984
Recordkeeping				$100	$100	$100
Travel					$0	$0
Total	**$0**		**$0**	**$3,884**	**$3,884**	**$3,884**

4.23 Subpart Y—Petroleum Refineries

Overview. For costing purposes, the monitoring options were divided into those that required the installation of new monitors and those that did not. As described below, the costs associated with installing and operating a new monitor also include costs of QA/QC checks and reporting. Costs for monitoring options that are not expected to require new monitoring systems were estimated by the anticipated amount of labor needed to carry out the monitoring option.

Labor Costs. Total labor costs are $12,300 in the first year and $6,500 in subsequent years; a majority of the labor costs are associated with planning, QA/QC checks, and recordkeeping and reporting and planning activities. These costs cover process emissions and stationary combustion sources.

Capital and O&M Costs. Average annualized capital equipment requirements are $1,200 per year. Equipment O&M costs approximately $7,300 per year. These costs cover process emissions and stationary combustion sources.

Stationary Combustion Costs. This subpart is not assigned additional stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use and recordkeeping ($1,700 per entity) costs.

Table 4-42. Subpart Y Petroleum Refineries: Labor Costs (2006$)

	Labor Hours																Labor Cost per Year per Reporting Unit/Facility	
	Electricity Manager $88.79		Refinery Manager $101.31		Industrial Manager $71.03		Lawyer $101.00		Electricity Eng/Tech $60.84		Refinery Eng/Tech $63.89		Industrial Eng/Tech $55.20		Admin $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning			3	0							52	4			5	0	$3,724	$271
QA/QC			2	0							36	4			4	0	$2,573	$271
Recordkeeping			2	2							33	33			3	3	$2,348	$2,348
Sampling, analysis, and calculations											23	23					$1,476	$1,476
Reporting			2	2							30	30			3	3	$2,172	$2,172
Total			**8**	**4**							**173**	**93**			**15**	**7**	**$12,292**	**$6,539**

Table 4-43. Subpart Y Petroleum Refineries: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	**Equipment Lifetime (years)**	**Annualized Capital Cost (per year)**	**O&M Costs (per year)**	**First Year**	**Subseq. Year**
Equipment (selection, purchase, installation)	$10,962	15	$1,204	$7,256	$8,460	$8,460
Performance testing					$0	$0
Recordkeeping					$0	$0
Travel					$0	$0
Total	**$10,962**		**$1,204**	**$7,256**	**$8,460**	**$8,460**

4.24 Subpart Z—Phosphoric Acid Production

Baseline Reporting. We are not aware of any phosphoric acid production facilities that are estimating and reporting emissions for internal GHG management programs or for state or voluntary reporting programs at the domestic or international level. Thus, we are assuming that no phosphoric acid production facilities are currently reporting emissions and that many of the proposed requirements will result in "additional" costs to meet reporting requirements.

Facilities are tracking and collecting the data required for estimating emissions such as such as phosphate rock feed rates and sampling and testing phosphate rock for its inorganic carbon contents. According to Jasinski (2008), the companies conduct analysis on the rock frequently to determine the P2O5 content and the level of impurities. According to CF industries (Falls, 2008), they analyze a composite of incoming phosphate rock for carbon contents on a daily basis. The phosphate rock consumed or entering the digestion process is also measured on a daily basis.

Therefore, we are assuming that the proposed requirements will result in "additional" costs primarily to meet EPA's reporting requirements. Specifically, we assume that additional costs will be incurred for preparing monitoring and QA/QC plans, performing the calculations, reporting the results, and maintaining records.

Overview. Insufficient data was available to differentiate costs for compiling data and conducting sampling across different facilities; hence, model facilities were not developed.

Professional judgment was used to develop cost estimates and sampling frequency was assumed not to differ by facility size.

Labor Costs. The labor costs are associated with planning are $1,600 in the first year and $500 in subsequent years related to industrial process emissions.

Capital and O&M Costs. There are no new capital equipment and O&M requirements for this subpart related to industrial process emissions.

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-44. Subpart Z Phosphoric Acid Production: Labor Costs (2006$)

	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility	
	Lawyer $101.00		Industrial Manager $71.03		Industrial Engineer/ Technician $55.20		Administrative Support $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning	1	1	8	2	16	4			$1,552	$464
QA/QC										
Recordkeeping										
Sampling and analysis										
Reporting										
Total	**1**	**1**	**8**	**2**	**16**	**4**			**$1,552**	**$464**

Table 4-45. Subpart Z Phosphoric Acid Production: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs						
Total	**$0**		**$0**	**$0**	**$0**	**$0**

4.25 Subpart AA—Pulp and Paper Manufacturing

Overview. The cost estimates of the proposed monitoring procedures for the pulp and paper sector for combination biomass/fossil fuel–fired boilers, kraft and soda chemical recovery furnaces, sulfite and semichemical combustion units, lime kilns, and use of makeup chemicals. Monitoring cost estimates for some of the other GHG sources in the pulp and paper sector (fossil fuel–fired boilers, gas turbines, thermal oxidizers, and RTOs) are also addressed.

Labor Costs. Total labor costs are $3,000 in the first year and subsequent years; a majority of the labor costs are associated with planning ($1,000) and recordkeeping ($1,300).

Capital and O&M Costs. Average annualized capital equipment requirements are $14,700 per year. Equipment O&M costs are approximately $400 per year.

Stationary Combustion Costs. This subpart is not assigned additional stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-46. Subpart AA Pulp and Paper: Labor Costs (2006$)

	Labor Hours																Labor Cost per Year per Reporting Unit/Facility	
	Electricity Manager $88.79		Refinery Manager $101.31		Industrial Manager $71.03		Lawyer $101.00		Electricity Eng/Tech $60.84		Refinery Eng/Tech $63.89		Industrial Eng/Tech $55.20		Admin $29.65			
Activity	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year
Planning													19	19			$1,041	$1,041
QA/QC																	$0	$0
Recordkeeping													24	24			$1,325	$1,325
Sampling, analysis, and calculations													12	12			$662	$662
Reporting																	$0	$0
Total													**55**	**55**			**$3,028**	**$3,028**

Table 4-47. Subpart AA Pulp and Paper: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)	$34,927	5	$14,731	$371	$15,102	$15,102
Performance testing						
Recordkeeping						
Travel						
Total	**$34,927**		**$14,731**	**$371**	**$15,102**	**$15,102**

4.26 Subpart BB—Silicon Carbide Production

Baseline Reporting. Under voluntary domestic initiatives (such as EPA's Climate Leaders and DOE's Climate Vision, DOE's 1605b), some facilities are reporting emissions source categories. The analysis assumes that facilities have measurements and records of consumption of the amount of petroleum coke as part of their routine operations and for accounting purposes.

Overview. Insufficient data was available to differentiate costs for compiling data and conducting sampling across different facilities; hence, model facilities were not developed. Professional judgment was used to develop cost estimates and sampling frequency was assumed not to differ by facility size. Reporting requires estimating CO_2 emissions based on quarterly measurement of the amount of petroleum coke consumed. This method uses plant-specific carbon content and carbon oxidation factors.

Labor Costs. Total labor costs are $2,200 in the first year and $1,000 in subsequent years; a majority of the labor costs are associated with planning ($1,600). Planning costs fall to $500 in subsequent years.

Capital and O&M Costs. There are no new capital equipment requirements for this subpart. Reporting requires approximately $800 of sampling O&M costs.

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-48. Subpart BB Silicon Carbide: Labor Costs (2006$)

Activity	Labor Rates (per hour): Lawyer $101.00 First Year	Lawyer $101.00 Subseq. Year	Industrial Manager $71.03 First Year	Industrial Manager $71.03 Subseq. Year	Industrial Engineer/ Technician $55.20 First Year	Industrial Engineer/ Technician $55.20 Subseq. Year	Administrative Support $29.65 First Year	Administrative Support $29.65 Subseq. Year	Labor Cost per Year per Reporting Unit/Facility First Year	Labor Cost per Year per Reporting Unit/Facility Subseq. Year
Planning	1	1	8	2	16	4			$1,552	$464
QA/QC									$0	$0
Recordkeeping									$0	$0
Sampling and analysis[a]					10	8	2	2	$611	$501
Reporting									$0	$0
Total	**1**	**1**	**8**	**2**	**26**	**12**	**2**	**2**	**$2,164**	**$965**

[a] Assumes four sampling events per year for one input (petroleum coke); for more information, please refer to the cost appendix.

Table 4-49. Subpart BB Silicon Carbide: Capital and O&M Costs (2006$)

Activity	Cost Categories: Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	Total Reporting Cost per Unit/Facility: First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs[a]				$800	$800	$800
Total	**$0**		**$0**	**$800**	**$800**	**$800**

[a] Refers to quarterly sampling of carbon contents of one input (petroleum coke); for more information, please refer to the cost appendix.

4.27 Subpart CC—Soda Ash Manufacturing

Baseline Reporting. Under voluntary domestic initiatives (such as DOE's Climate Vision, DOE's 1605b), the Industrial Minerals Association North America (IMA-NA), which represents soda ash producers as a sector, has undertaken voluntary efforts to develop a GHG emissions protocol (based default emissions factors), educate association members about measuring and reporting GHG emissions, and track emissions intensity of production for the sector (more information is available at: http://www.climatevision.gov/sectors/minerals/index.html).

We do not know how many soda ash companies are currently implementing this approach at the facility level to meet internal GHG management programs or state or voluntary reporting programs at the domestic or international level. We are assuming that no soda ash production facilities are currently reporting emissions and that many of the proposed requirements will result in "new" or "additional" costs to meet reporting requirements.

However, soda ash production facilities are currently collecting and tracking the data required for estimating process-related CO_2 emissions on a routine basis. We understand that soda ash producers sample and measure purity of soda ash and/or trona in-house on a routine basis (i.e., inorganic carbon contents of trona). We are assuming that the proposed requirements will result in "additional" costs primarily to meet EPA's reporting requirements. Specifically, we are assuming that additional costs incurred will be for preparing monitoring and QA/QC plans, performing the calculations, reporting the results, and maintaining records (essentially developing a monitoring plan, reporting, recordkeeping, and QA/QC).

Overview. Insufficient data was available to differentiate costs for compiling data and conducting sampling across different facilities; hence, model facilities were not developed. Professional judgment was used to develop cost estimates and sampling frequency was assumed not to differ by facility size.

Labor Costs. Total labor costs are associated with planning ($1,600). Planning costs fall to $500 in subsequent years.

Capital and O&M Costs. There are no new capital equipment and O&M requirements for this subpart.

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-50. Subpart CC Soda Ash: Labor Costs (2006$)

	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility	
	Lawyer $101.00		Industrial Manager $71.03		Industrial Engineer/ Technician $55.20		Administrative Support $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning	1	1	8	2	16	4			$1,552	$464
QA/QC									$0	$0
Recordkeeping									$0	$0
Sampling and analysis									$0	$0
Reporting									$0	$0
Total	**1**	**1**	**8**	**2**	**16**	**4**			**$1,552**	**$464**

Table 4-51. Subpart CC Soda Ash: Capital and O&M Costs (2006$)

	Cost Categories				Total Reporting Cost per Unit/Facility	
Activity	**Capital Cost**	**Equipment Lifetime (years)**	**Annualized Capital Cost (per year)**	**O&M Costs (per year)**	**First Year**	**Subseq. Year**
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs						
Total	**$0**		**$0**	**$0**	**$0**	**$0**

4.28 Subpart DD—Sulfur Hexafluoride (SF_6) from Electric Power Systems

Overview. The model facility for electric power systems is an electric utility that operates an average amount (nameplate capacity) of SF_6-containing transmission equipment. Costs are not expected to vary widely among utilities because all utilities would track the same set of quantities (SF_6 stored, acquired, and disbursed; equipment installed and retired), and the costs of tracking and reporting these quantities are relatively modest.

The model facility is assumed to already have the capital and technical capability to monitor and report emissions of SF_6 using a mass-balance formula. To use the formula, facilities must track their SF_6 inventory in cylinders, SF_6 acquisitions, and SF_6 disbursements, as well as their equipment commissioning and decommissioning. These data are already tracked by utilities, but not necessarily as closely and comprehensively as required to develop all utility level mass-balance inputs. Thus, as discussed below, the model facility is assumed to incur some costs for tracking and reporting SF_6 emissions.

Labor Costs. Total labor costs are $2,200 in the first year and subsequent years; a majority of the labor costs are associated with planning activities ($1,600).

Capital and O&M Costs. There are no new capital equipment requirements. A small amount of O&M recordkeeping is required ($12).

Stationary Combustion Costs. This subpart is not assigned additional stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use and reporting ($500) costs.

Table 4-52. Subpart DD SF_6 Electrical Power Systems: Labor Costs (2006$)

Activity	Legal $101.00 First Year	Legal $101.00 Subseq. Year	Managerial $71.03 First Year	Managerial $71.03 Subseq. Year	Technical $55.20 First Year	Technical $55.20 Subseq. Year	Clerical $29.65 First Year	Clerical $29.65 Subseq. Year	Labor Cost per Year per Reporting Unit/Facility[a] First Year	Labor Cost per Year per Reporting Unit/Facility[a] Subseq. Year
Planning			1	1	2	2			$154	$154
QA/QC										
Recordkeeping									$6	$6
Sampling and analysis (calculations)			4	4	17	17	11	11	$1,549	$1,549
Reporting			4	4	4	4	2	2	$492	$492
Total			**9**	**9**	**22**	**22**	**13**	**13**	**$2,201**	**$2,201**

[a] Assumes annual sampling; for more information, please refer to the cost appendix.

Table 4-53. Subpart DD SF_6 Electrical Power Systems: Capital and O&M Costs (2006$)

Activity	Cost Categories: Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	Total Reporting Cost per Unit/Facility: First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping				$12	$12	$12
Travel						
Sampling costs						
Total	**$0**		**$0**	**$12**	**$12**	**$12**

4.29 Subpart EE—Titanium Dioxide Production

Baseline Reporting. In this sector, data are not available on how many companies are currently estimating and reporting GHG emissions at the facility level to meet internal GHG management programs or state or voluntary reporting programs at the domestic or international level. We are assuming that no titanium dioxide production facilities are currently reporting emissions and that many of the proposed requirements will result in "new" or "additional" costs to meet reporting requirements.

However, many titanium dioxide production facilities are currently tracking much of the data required to estimate process-related CO_2 emissions on a routine basis (calcined petroleum coke consumption). We are assuming that the proposed requirements will result in "additional" costs primarily to meet EPA's reporting requirements. For example, we assume that additional costs incurred will be for preparing monitoring and QA/QC plans, performing the calculations, reporting the results, and maintaining records (essentially developing a monitoring plan, reporting, recordkeeping, and QA/QC).

Overview. Insufficient data was available to differentiate costs for compiling data and conducting sampling across different facilities; hence, model facilities were not developed. Professional judgment was used to develop cost estimates and sampling frequency was assumed not to differ by facility size.

Labor Costs. The labor costs are associated with planning are $1,600 in the first year and $500 in subsequent years related to industrial process emissions.

Capital and O&M Costs. There are no new capital equipment and O&M requirements for this subpart related to industrial process emissions.

Stationary Combustion Costs. This subpart is assigned stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-54. Subpart EE Titanium Dioxide: Labor Costs (2006$)

Activity	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility	
	Lawyer $101.00		Industrial Manager $71.03		Industrial Engineer/ Technician $55.20		Administrative Support $29.65			
	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year
Planning	1	1	8	2	16	4			$1,552	$464
QA/QC										
Recordkeeping										
Sampling and analysis										
Reporting										
Total	**1**	**1**	**8**	**2**	**16**	**4**			**$1,552**	**$464**

Table 4-55. Subpart EE Titanium Dioxide: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs						
Total	**$0**		**$0**	**$0**	**$0**	**$0**

4.30 Subpart FF—Underground Coal Mines

Overview. For purposes of this RIA, each mine exceeding the MSHA threshold was assumed to have two ventilation shafts where quarterly sampling was conducted. For mine degasification systems, only those systems where degasification systems are in place were considered. For these facilities, one degasification well per facility was assumed. For remote gob gas vent wells/holes that do not currently monitor degasified gas volumes produced, incremental costs are also associated with installing simple monitoring equipment on these remote gob gas vent holes. For purposes of developing costs, five gob wells were assumed per long wall panel, applied to the approximately 40 long wall mines in the United States that do not monitor such vents.[1]

Labor Costs. For coal mining, labor categories include manager, industrial engineer/technician, and administrative support. The labor costs are associated with oversight, auditing, and/or duplication of MSHA inspectors during quarterly inspections to estimate ventilation air emissions. Total labor costs are approximately $15,600 in the first year and $15,400 in subsequent years. The majority of these costs ($8,000) are associated with sampling and analysis activities.

Capital and O&M Costs. The capital investment is $6,200. Using a lifetime of 4 years and an interest rate of 7%, the annualized capital expenditures are approximately $1,700 per affected entity. An additional $4,000 of O&M costs are required per year.

Stationary Combustion Costs. This subpart is not assigned additional stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned recordkeeping ($1,700 per entity) and reporting ($500) costs.

[1]Personal communication, Fred H. Menke, Jr., Supervisory IT Specialist, Mine Safety and Health Administration, to Michael Godec, Advanced Resources International, April 25, 2008.

Table 4-56. Subpart FF Underground Coal Mines: Labor Costs (2006$)

Activity	Labor Hours: Senior Manager/ Lawyer $101.31 First Year	Senior Manager/ Lawyer $101.31 Subseq. Year	Industrial Manager $71.03 First Year	Industrial Manager $71.03 Subseq. Year	Industrial Engineer/ Technician $55.20 First Year	Industrial Engineer/ Technician $55.20 Subseq. Year	Administrative Support $29.65 First Year	Administrative Support $29.65 Subseq. Year	Labor Cost per Year per Reporting Unit/Facility First Year	Labor Cost per Year per Reporting Unit/Facility Subseq. Year
Planning			40	40	81	80	8	8	$7,573	$7,494
QA/QC										
Recordkeeping										
Sampling and analysis			17	17	118	117	9	8	$8,018	$7,890
Reporting										
Total			**58**	**57**	**199**	**197**	**17**	**16**	**$15,591**	**$15,384**

Table 4-57. Subpart FF Underground Coal Mines: Capital and O&M Costs (2006$)

Activity	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	Total Reporting per Unit/Facility Cost: First Year	Total Reporting per Unit/Facility Cost: Subseq. Year
Equipment (selection, purchase, installation)[a]	$6,200	4	$1,677		$1,677	$1,677
Performance testing						
Recordkeeping						
Travel						
Sampling costs				$4,000	$4,000	$4,000
Total	**$6,200**	**4**	**$1,677**	**$4,000**	**$5,677**	**$5,677**

[a] 3-year life for ventilation shaft air sampling devices.

4.31 Subpart GG—Zinc Production

Baseline Reporting. Under voluntary domestic initiatives (such as EPA's Climate Leaders and DOE's Climate Vision, DOE's 1605b), some facilities are reporting emissions source categories. The analysis assumes that facilities have measurements and records of consumption of raw materials such as reducing agents as part of their routine operations and for accounting purposes.

Overview. Insufficient data was available to differentiate costs for compiling data and conducting sampling across different facilities; hence, model facilities were not developed. Professional judgment was used to develop cost estimates and sampling frequency was assumed not to differ by facility size. Reporting requires annual carbon balance using monthly off-site sampling of the amount of carbon contained in the reducing agent, usually metallurgical coke.

Labor Costs. A majority of the labor costs are associated with planning ($1,600 in the first year) and sampling and analysis activities ($1,600). Planning activity costs fall to $500 in subsequent years.

Capital and O&M Costs. There are no new capital equipment requirements for this subpart. Reporting requires approximately $2,400 of sampling O&M costs. The costs are associated with process emissions.

Stationary Combustion Costs. This subpart is assigned additional stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-58. Subpart GG Zinc: Labor Costs (2006$)

Activity	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility	
	Lawyer $101.00		Industrial Manager $71.03		Industrial Engineer/ Technician $55.20		Administrative Support $29.65			
	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year
Planning	1	1	8	2	16	4			$1,552	$464
QA/QC									$0	$0
Recordkeeping									$0	$0
Sampling and analysis[a]					26	24	6	6	$1,613	$1,503
Reporting										
Total	**1**	**1**	**8**	**2**	**42**	**28**	**6**	**6**	**$3,165**	**$1,966**

[a] Refers to monthly sampling of carbon contents for one input, which is generally petroleum coke, metallurgical coke, or anthracite coal. For more information, please refer to the cost appendix.

Table 4-59. Subpart GG Zinc: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs[a]				$2,400	$2,400	$2,400
Total	**$0**		**$0**	**$2,400**	**$2,400**	**$2,400**

[a] Refers to monthly sampling of carbon contents for one input, which is generally petroleum coke, metallurgical coke, or anthracite coal. For more information, please refer to the cost appendix.

4.32 Subpart HH—Landfills

Overview. Costs were developed to model emissions using the IPCC waste model (or similar model) using the waste composition option (all landfills). Tables 4-60 and 4-61 report the average values for all landfills (MSW only, pulp and paper, and food processing).

Labor Costs**.** Labor costs are estimated to be approximately $900 per entity in the first year and $400 in subsequent years.

Capital and O&M Costs**.** The capital investment is $1,600. Using a lifetime of 15 years and an interest rate of 7%, the annualized capital expenditures are approximately $175 per affected entity. There is an additional $500 in equipment O&M costs per year.

Stationary Combustion Costs**.** This subpart is not assigned additional stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs**.** This subpart is assigned electricity use and recordkeeping ($1,700 per entity) costs.

Table 4-60. Subpart HH Landfills: Labor Costs (2006$)

	Labor Hours																Labor Cost per Year per Reporting Unit/Facility	
	Electricity Manager $88.79		Refinery Manager $101.31		Industrial Manager $71.03		Lawyer $101.00		Electricity Eng/Tech $60.84		Refinery Eng/Tech $63.89		Industrial Eng/Tech $55.20		Admin $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning					0.2								3.8		0.4		$237	$0
QA/QC					0.1	0.0							1.9	0.8	0.2	0.1	$119	$47
Recordkeeping					0.4	0.2							7.6	4.6	0.8	0.5	$471	$283
Sampling, analysis, and calculations																		
Reporting					0.1	0.0							1.2	0.8	0.1	0.1	$71	$47
Total					**0.8**	**0.2**							**15.0**	**6.2**	**1.5**	**1.0**	**$898**	**$378**

Note: Average values for all landfills (MSW, pulp and paper, and food processing.

Table 4-61. Subpart HH Landfills: Capital and O&M Costs (2006$)

Activity	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	Total Reporting per Unit/Facility Cost	
					First Year	Subseq. Year
Equipment (selection, purchase, installation)	$1,596	15	$175	$467	$642	$1,109
Performance testing						
Recordkeeping						
Travel						
Total	**$1,596**		**$175**	**$467**	**$642**	**$1,109**

Note: Average values for all landfills (MSW, pulp and paper, and food processing).

4.33 Subpart II—Wastewater

Overview. For this source category, EPA evaluated ethanol refinery wastewater treatment plants, pulp and paper mill wastewater treatment plants, and petroleum refinery wastewater treatment plants to represent the types of wastewater treatment systems with the greatest potential to exceed the GHG threshold. These costs were added to the appropriate industrial subpart (J, AA, and Y).

For each industry category, EPA first attempted to locate any plant-level datasets that would allow direct calculation of GHG emissions by plant. Where plant-level data were incomplete, EPA used default national-level data from the National Inventory to fill in missing data. Where plant-level data were unavailable, EPA instead determined the production levels for each industry that would trigger emissions over any of the thresholds of interest, and used best professional judgment to estimate how many plants would meet the production levels.

For pulp and paper mills, EPA used the most readily available plant-level dataset, which contains 94 of the largest U.S. pulp and paper mills (as of 1995). The dataset contains pulp production data collected by U.S. EPA's Office of Water during development of national effluent limitation guidelines and standards for this industry. As such, the mills are not identified by name. Because the dataset did not include plant-specific information on wastewater generation rates, influent BOD or COD levels, or treatment processes on site, EPA used default values from the National Inventory.

For petroleum refineries, EPA obtained a plant-specific dataset from the Energy Information Administration (EIA), with refinery capacity for all facilities as of January 2007.

The EIA data did not include plant-specific information on wastewater generation rates, influent BOD or COD levels, or treatment processes on site. Therefore, EPA used default values from the National Inventory and other reporting guidelines.

Labor Costs. The annual cost to operate the continuous measurement system includes the cost to calibrate the analyzers monthly and to compile annual emission reports. These tasks are assumed to require 14 hours per year for an industrial technician. The annual costs also include $200 for gas analyzer calibration kits. The total annual costs including labor and calibration kits are $973. EPA estimates that 2 hours of labor is needed per month to collect and organize flow data, for a total annual cost of $871. EPA estimates that 1 hour of labor is needed for each sampling episode. Each COD wastewater sample is estimated to have analytical costs of $30, based on an average of laboratory rate schedules. EPA assumed monthly sampling episodes, which results in an annual sampling cost of $995.

Capital and O&M Costs. EPA assumes that continuous gas composition monitoring from anaerobic digestion systems would require a continuous gas composition analyzer, a temperature sensor, a gas pressure sensor, and a data logger. The total capital cost for these items is $3,280–$4,000; EPA estimates these costs to be $3,640. For wastewater treatment operations, EPA used an equipment lifetime of 10 years and interest rate of 7% to annualize capital costs. Annualized capital costs are $344 per year. The costs only apply to ethanol facilities and nine meat processing facilities.

Table 4-62. Subpart II Wastewater: Labor Costs (2006$)

	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility[a]	
	Legal $101.00		Managerial $71.03		Technical $55.20		Clerical $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning										
QA/QC[a]					18	18			$973	$973
Recordkeeping							29	29	$871	$871
Sampling and analysis (calculations)										
Reporting							34	34	$995	$795
Total	**0**	**0**	**0**	**0**	**18**	**18**	**63**	**63**	**$2,839**	**$2,639**

[a] Applies to ethanol and nine meat processing facilities only.

Table 4-63. Subpart II Wastewater: Capital and O&M Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)	$3,640	10	$344		$344	$344
Performance testing						
Recordkeeping						
Travel						
Sampling costs						
Total	**$3,640**		**$344**	**$0**	**$344**	**$344**

[a] Applies to ethanol and nine meat processing facilities only.

4.34 Subpart JJ—Manure Management

Baseline Reporting. Farms maintain records on the number and types of animals present; however, they generally do not run calculations for CH_4 and N_2O generation. It is therefore assumed that the costs for monitoring and reporting emissions are new costs.

Overview. For this source category, EPA developed a number of model farms to represent the manure management systems that are most common on large farms and have the greatest potential to exceed the GHG thresholds. Operations were divided into model farms representing 12 distinct manure management systems:

- a beef farm with a pasture system;
- a beef feedlot;
- a dairy farm with an anaerobic lagoon system without solid separation;
- a dairy farm with an anaerobic lagoon system with solid separation;
- a dairy farm with a liquid/slurry system without solid separation;
- a dairy farm with a liquid/slurry system with solid separation;
- a farrow-to-finish swine farm with a deep pit system;
- a farrow-to-finish swine farm with an anaerobic lagoon system;
- a caged layer farm with an anaerobic lagoon system;
- a caged layer farm with manure drying;

- a turkey farm with bedding (litter); and
- a broiler farm with bedding (litter).

EPA determined the number of head that would need to be present at each model farm to reach the reporting threshold under consideration (assuming no anaerobic digester is present on the farm. Based on information from EPA's Development Document for the Final Revisions to the National Pollutant Discharge Elimination System (NPDES) Regulation and the Effluent Guidelines for Concentrated Animal Feeding Operations (CAFOs), model dairy farms were assumed to have population distributions that are comprised of 63% dairy cows, 19% dairy heifers, and 19% calves. At each model dairy farm, the heifers and calves were assumed to be managed on dry lots, and the dairy cows were managed on liquid systems (either anaerobic lagoons or liquid/slurry systems). The population distributions for beef and swine were estimated based on the U.S. total populations from the National Inventory; this estimate assumes that all U.S. farms would have the same distribution of animal types.

Labor Costs. Assigning labor hours for all cost elements was based on expert judgment. First year planning requires 10 hours at a cost of $228. EPA estimates annual costs for manure sampling based on *The Cost Methodology for the Final Revisions to the National Pollutant Discharge Elimination System Regulation and the Effluent Guidelines for Concentrated Animal Feeding Operations* (EPA, December 2002, EPA-821-R-03-004). Labor costs for manure sampling are estimated to be $16.12 an hour for farm labor with an hour of labor needed for each sampling episode. Each sample is estimated to have analytical costs of $40. EPA assumed monthly sampling episodes, which results in an annual sampling cost of $193. The farm owner is responsible for collecting the data required to perform the calculations required by the rule. These data include the population of animals at the facility, the average weight of the animals, and the annual average ambient temperature. The annual gathering of these data, performing the calculations, and completing the paperwork are estimated to require 4 hours at an estimated cost of $198. The annual cost to operate the continuous measurement system includes the cost to calibrate the analyzers monthly and to compile annual emission reports. These tasks are assumed to require 14 hours per year at a rate of $49.53 per hour for the farm owner or designee. The annual costs also include $200 for gas analyzer calibration kits. The total annual cost, including labor and calibration kits, is $693.

Capital and O&M Costs. For one farm, reporting requiring continuous gas composition monitoring equipment for anaerobic digestion systems would require a continuous gas flow meter, a continuous gas composition analyzer, a temperature sensor, a gas pressure sensor, and a data logger; the total capital cost is $6,750. EPA used an equipment lifetime of 10 years and an interest rate of 7% to annualize capital costs. Annualized capital costs are $961 per year. For the other 42 farms, a manure sampler is required with a total capital cost of $30. Annualized capital costs are $4 per year.

Stationary Combustion Costs. This subpart is not assigned additional stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-64. Subpart JJ Manure Management: Labor Costs (2006$)

	Labor Hours					
	Farm, Ranch, and Other Agricultural Manager ($49.53/hr)		Farm worker ($16.12/hr)		Labor Cost per Year per Reporting Unit/Facility	
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning	2		8		$228	
Sampling			12	12	$193	$193
Calculations	4	4			$198	$198
Monitoring—digester	14	14			$693	$693
Total	**20**	**18**	**20**	**12**	**$1,313**	**$1,085**

Table 4-65a. Subpart JJ Manure Management: Capital and O&M Costs (2006$)

					Total Reporting per Unit/Facility Cost	
Activity	**Capital Cost**	**Equipment Lifetime (years)**	**Annualized Capital Cost (per year)**	**O&M Costs (per year)**	**First Year**	**Subseq. Year**
Equipment (selection, purchase, installation)	$6,750	10	$961	$1,092	$2,330	$2,053
Recordkeeping						
Total	**$6,750**		**$961**	**$1,092**	**$2,330**	**$2,053**

Note: Applies to one farm.

Table 4-65b. Subpart JJ Manure Management: Capital and O&M Costs (without Digesters) (2006$)

Activity	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	Total Reporting per Unit/Facility Cost	
					First Year	Subseq. Year
Equipment (selection, purchase, installation)	$30	10	$4	$872	$1,153	$876
Recordkeeping						
Total	**$30**		**$4**	**$872**	**$1,153**	**$876**

Note: Applies to 42 farms.

4.35 Subpart KK—Suppliers of Coal and Coal-based Products & Subpart LL—Suppliers of Coal-based Liquid Fuels

Overview. All coal mines are required to report under this rule. A mine is defined as any facility considered by MSHA to be actively engaged in the production of coal during the reporting year. There are two model facilities: those producing 100,000 tons or more annually during the reporting year (large mines) and those producing less than 100,000 tons annually (small mines). A section for facilities that produce liquid fuel from coal is also includes in this rule. However, since no such facilities are in operation in the United States, a cost analysis was not conducted. It is anticipated that such facilities may be in operation in the future.

Labor Costs. Labor costs are estimated to be approximately $6,800 per entity in the first year and $2,500 in subsequent years. Most of the costs are related to registration and monitoring.

Capital and O&M Costs. The annualized capital expenditures and O&M are less than $5 per year.

Stationary Combustion Costs. This subpart is not assigned additional stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use only.

Table 4-66. Subparts KK & LL Coal Suppliers: Labor Costs (2006$)

	Labor Hours																Labor Cost per Year per Reporting Unit/Facility	
	Electricity Manager $88.79		Refinery Manager $101.31		Industrial Manager $71.03		Lawyer $101.00		Electricity Eng/Tech $60.84		Refinery Eng/Tech $63.89		Industrial Eng/Tech $55.20		Admin $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Registration					11	2	21	3					16	3	6	1	3,954	609
Monitoring					13	8							24	15			2,276	1,410
Reporting													1	1	1	1	87	87
Archiving															3	3	81	81
Auditing					2	2							3	3	2	1	377	295
Total	**0**	**0**	**0**	**0**	**26**	**11**	**21**	**3**	**0**	**0**	**0**	**0**	**45**	**21**	**12**	**6**	**6,775**	**2,482**

Table 4-67. Subparts KK & LL Coal Suppliers: Capital and O&M Costs (2006$)

Activity	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	Total Reporting per Unit/Facility Cost	
					First Year	Subseq. Year
Equipment (selection, purchase, installation)					$0	$0
Performance testing				$1	$1	$1
Recordkeeping	$4	5	$1		$1	$1
Travel					$0	$0
Total	**$4**		**$1**	**$1**	**$2**	**$2**

4.36 Subpart MM—Suppliers of Petroleum Products

Overview. All refineries are required to report under this rule. The unit of reporting is the individual refinery. No distinction has been made between the sizes of refineries for estimating the monitoring costs because the rule would require additional processing of data that refineries already collect and report. Under the rule, individual operating refineries are the reporters as opposed to the parent company. For example, Exxon Corporation owns and operates six refineries within the United States. Each operating refinery will be a reporter under this rule, not Exxon Corporation.

Capital and O&M Costs. The capital investment is $1,600. Using a lifetime of 15 years and an interest rate of 7%, the annualized capital expenditures are approximately $175 per affected entity. There is an additional $500 in equipment O&M costs per year.

Labor Costs. Labor costs are estimated to be approximately $9,300 per entity in the first year and $3,500 in subsequent years. Most of the costs are related to registration and monitoring.

Stationary Combustion Costs. This subpart is not assigned additional stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is not assigned any additional costs.

Table 4-68. Subpart MM Petroleum Suppliers: Labor Costs (2006$)

Activity	Labor Hours: Senior Manager $101.31		Environmental Manager $88.79		Environmental Engineer $71.03		Legal Counsel $101.00		Labor Cost per Year per Reporting Unit/Facility	
	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year	First Year	Subseq. Year
Registration	4	2	16	4	40	8	7	2	$5,314	$1,398
Monitoring	2	0	12	2	19	6	0	0	$2,567	$606
Reporting	1	0	4	1	7	1	0	0	$1,010	$178
Archiving	0	0	1	1	4	4	0	0	$415	$415
Auditing	0	1	0	4	0	4	0	1	$0	$936
Total	**8**	**3**	**33**	**13**	**70**	**24**	**7**	**3**	**$9,305**	**$3,533**

Table 4-69. Subpart MM Petroleum Suppliers: Capital and O&M Costs (2006$)

Activity	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	Total Reporting per Unit/Facility Cost: First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Total	**$0**		**$0**	**$0**	**$0**	**$0**

4.37 Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids

Overview. All local distribution companies (LDCs) are required to report under this rule. The unit of reporting is the individual LDC. No distinction has been made between the sizes of LDCs for estimating the monitoring costs because the rule would require additional processing of data that LDCs already collect and report. Under the rule, individual operating LDCs are the reporters as opposed to holding companies. For example, National Grid PLC is a holding company that operates two LDCs in New York, namely Keyspan on Long Island and Niagara

Mohawk in upstate; and other LDCs in New Hampshire, Massachusetts, and Rhode Island. Each operating company in each state will be a reporter under this rule, not National Grid.

The rule covers all natural gas processing plants. The unit of reporting is the processing plant or facility. As defined in the rule, these are plants designed to separate and recover natural gas liquids (NGLs) or other gases and liquids from a stream of produced natural gas and to control the quality of natural gas marketed. Thus, the plants covered deliver pipeline quality natural gas to pipelines but not include field gathering and boosting stations or fractionation plants that do not deliver processed gas but only fractionate NGL streams. Companies may own more than one processing plant: each plant is required to report under this rule. No distinction has been made between the sizes of natural gas processors for estimating the monitoring costs because the rule only would require additional processing of data that natural gas processors already collect as part of their ongoing business and report on EIA Form 816.

Labor Costs. Labor costs are estimated to be approximately $1,300 per entity in the first year and $800 in subsequent years. Most of the costs are related to registration and monitoring.

Capital and O&M Costs. There are no new capital equipment or O&M expenses.

Stationary Combustion Costs. This subpart is not assigned additional stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use only.

Table 4-70. Subpart NN Natural Gas Suppliers: Labor Costs (2006$)

Average	Labor Hours																Labor Cost per Year per Reporting Unit/Facility	
	Electricity Manager $88.79		Refinery Manager $101.31		Industrial Manager $71.03		Lawyer $101.00		Electricity Eng/Tech $60.84		Refinery Eng/Tech $63.89		Industrial Eng/Tech $55.20		Admin $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Registration					3	1	2	1	0	0	0	0	5	2	1	0	761	288
Monitoring					1	1	1	0	0	0	0	0	5	3	1	1	413	278
Reporting					0	0	0	0	0	0	0	0	1	1	1	1	105	105
Archiving					0	0	0	0	0	0	0	0	0	0	0	0	20	20
Auditing					0	0	0	0	0	0	0	0	0	1	0	0	22	101
Total	**0**	**0**	**0**	**0**	**5**	**2**	**3**	**2**	**0**	**0**	**0**	**0**	**11**	**7**	**3**	**3**	**1,321**	**793**

Table 4-71. Subpart NN Natural Gas Suppliers: Capital and O&M Costs (2006$)

Activity	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	Total Reporting per Unit/Facility Cost	
					First Year	Subseq. Year
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Total	**$0**		**$0**	**$0**	**$0**	**$0**

4.38 Subpart OO—Suppliers of Industrial Greenhouse Gases

Overview. The industrial gas supply category includes facilities that produce N_2O or fluorinated GHGs (e.g., HFCs, PFCs, SF_6, NF3, and fluorinated anesthetics), importers of N_2O or fluorinated GHGs, and exporters of N_2O or fluorinated GHGs. As described below, costs were estimated for model facilities that encompass the likely combinations of these entities and activities. In addition, because importers of fluorinated GHGs and N_2O frequently also import CO_2, and because importers would be required to sum their CO_2-equivalent imports across gases to determine whether they exceeded the reporting threshold, this analysis considers imports of CO_2. While a TSD was prepared for imports of gas in products, EPA is not proposing to require that importers of products report. Thus, imports in products are not included in the totals below. However, EPA estimates that the burden and cost per importer for importers of pre-charged products would be comparable to (slightly smaller than) those estimated below for producers and importers of bulk gases.

There are four model facilities that fall under Industrial Gas Supply. Each one represents the specific reporting activities (production, import, export, transformation, or destruction) and costs relevant to each category.

Labor Costs. Labor costs are estimated to be approximately $1,300 per entity in the first year and $800 in subsequent years. Most of the costs are related to registration and monitoring.

Capital and O&M Costs. There are no new capital equipment or O&M expenses.

Stationary Combustion Costs. This subpart is not assigned additional stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping, and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-72. Subpart OO Suppliers of Industrial Gases: Labor Costs (2006$)

	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility[a]	
	Legal $101.00		Managerial $71.03		Technical $55.20		Clerical $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning	0	0	0	0	0	0	0	0	$0	$0
QA/QC	0	0	0	0	0	0	0	0	$0	$0
Recordkeeping	0	0	0	0	0	0	0	0	$0	$0
Sampling and analysis (calculations)	0	0	4	4	12	12	0	0	$908	$908
Reporting	0	0	0	0	0	0	0	0	$0	$0
Total	**0**	**0**	**4**	**4**	**12**	**12**	**0**	**0**	**$908**	**$908**

[a] Assumes annual sampling; for more information, please refer to the cost appendix.

Table 4-73. Subpart OO Suppliers of Industrial Gases: Capital and O&M Costs (2006$)

	Cost Categories				Total Reporting Cost per Unit/Facility	
Activity	**Capital Cost**	**Equipment Lifetime (years)**	**Annualized Capital Cost (per year)**	**O&M Costs (per year)**	**First Year**	**Subseq. Year**
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs[a]						
Total	**$0**		**$0**	**$0**	**$0**	**$0**

4.39 Subpart PP—Suppliers of Carbon Dioxide (CO_2)

Overview. All 13 existing CO_2 capture sites and CO_2 production well sites are included in the cost estimate. The monitoring option for each site involves a CO_2 flow meter, and therefore the monitoring cost for each site is the same. Hence, model facilities were not needed for characterizing the facility and estimating the relevant costs.

Labor Costs. Labor costs are estimated to be approximately $237 per entity in the first year and subsequent years.

Capital and O&M Costs. There are no new capital equipment or O&M expenses.

Stationary Combustion Costs. This subpart is not assigned additional stationary combustion costs as described in subpart C (Table 4-3).

Electricity Use, Recordkeeping and Reporting Costs. This subpart is assigned electricity use, recordkeeping ($1,700 per entity) and reporting ($500) costs.

Table 4-74. Subpart PP Suppliers of CO_2: Labor Costs (2006$)

	Labor Rates (per hour)								Labor Cost per Year per Reporting Unit/Facility	
	Lawyer $101.00		Industrial Manager $71.03		Industrial Engineer/ Technician $55.20		Administrative Support $29.65			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning										
QA/QC										
Recordkeeping										
Sampling and analysis[a]			1	1	3	3			$237	$237
Reporting										
Total			**1**	**1**	**3**	**3**			**$237**	**$237**

[a] Assumes four data collection events per year for one input (CO_2 flow meter data); no estimates for calculations are provided in this row. For more information refer to the cost appendix.

Table 4-75. Subpart PP Suppliers of CO_2: Capital and O&M Costs (2006$)

	Cost Categories				Total Reporting per Unit/Facility Cost	
Activity	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Years
Equipment (selection, purchase, installation)						
Performance testing						
Recordkeeping						
Travel						
Sampling costs						
Total	**$0**		**$0**	**$0**	**$0**	**$0**

Note: There are no capital or O&M costs for the monitoring option for the CO_2 Capture Sites and CO_2 Production Well Sites Category CO_2 flow meters are assumed to exist at all existing sites and that there is no incremental O&M cost for their operation.

4.40 Mobile Sources

Mobile source costs for the proposed rule are estimated for upstream vehicles and engine manufactures and are associated with the fixed certification costs of a new regulation. Typically, our cost analysis focuses on variable costs associated with engine or vehicle technologies needed to meet new emissions standards. However, since we are not proposing new emission standards, the proposed requirements have no such variable costs. Certification costs, including those estimated here, are typically modest relative to the much larger costs of redesigning and modifying vehicles and engines to comply with new emissions standards. Costs are categorized into reporting and recordkeeping (labor) costs, new test equipment/facility (equipment) costs, and incremental testing (operating and maintenance) costs.

4.40.1 Source Description and Baseline Reporting

The concept of a reporting "threshold" for mobile engine manufacturers differs from the approach proposed for other sectors in this rule. EPA would not have manufacturers determine their eligibility based on total tons emitted per year. EPA's current mobile source criteria pollutant control programs are based on emissions rates over prescribed test cycles rather than tons per year estimates. Since EPA is proposing to build on our existing system, we believe that a threshold based on manufacturer size is appropriate for the mobile source sector. Although the emission rates of some vehicles and engines would not be reported, we do not believe this is a concern because the technologies—and thus emission rates—from larger manufacturers represent the same basic technologies and emission rates of essentially all vehicles and engines. Estimates of the number of affected manufacturers are provided in Table 4-76.

Baseline Reporting. Manufacturers currently conduct vehicle and engine emissions testing as part of EPA's existing emissions control programs. Manufacturers already measure CO_2, although in some cases are not currently required to report CO_2 test results to EPA. N2O and CH_4 measurement and reporting would be new for several mobile source categories, as discussed below. Manufacturers not already measuring N_2O and CH_4 would need to install new measurement equipment, but new testing would not be needed since these pollutants would be measured over existing tests. The A/C idle test for vehicles would be a new requirement with associated incremental testing costs, as discussed below. Regarding the aircraft engine category, we assume that there are no costs associated with proposed reporting requirements, but request comment in the preamble on the degree to which these engine manufacturers already have the necessary equipment in their certification test cells.

Table 4-76. Mobile Source Vehicle and Engine Categories

Category	Estimated Number of Affected Manufacturers
Light-duty vehicles	33
Highway heavy-duty vehicles (chassis-certified)	3
Highway heavy-duty engines	11
Highway motorcycles	46
Nonroad diesel engines	66
Marine diesel engines	27
Locomotives	6
Nonroad small spark ignition engines	81
Nonroad large spark ignition engines	9
Marine spark ignition engines/personal watercraft	12
Snowmobiles	4
Off-highway motorcycles and ATVs	52
Mobile sources	350

* Includes 1,250 fuel economy and 1,812 in-use verification datasets.

4.40.2 Labor Costs: Reporting and Recordkeeping

Reporting and recordkeeping cost estimates account for the staff and management hours needed to review and submit new data to EPA as part of the certification process. For all categories, manufacturers would be required to report CO_2, CH_4, and N_2O emissions levels.

Vehicle manufacturers would also be required to submit CO_2 emissions results from the new A/C idle test, and A/C system scoring results. Manufacturers have been submitting certification data to EPA for many years, and the process for collecting and submitting data to EPA is highly automated for most manufacturers. Once the test cells and computer systems are set up to collect and submit the data, the act of submitting the incremental emissions data to EPA as part of certification would be routine. We therefore estimate a minimal incremental burden for reporting, 10 to 20 minutes each for managerial staff, engineering staff, and secretarial staff per vehicle/engine family, to ensure the appropriate data are submitted to EPA. For light-duty vehicles, manufacturers would report emissions results for both fuel economy testing and in-use verification testing.

For light-duty vehicles, there is an additional reporting and recordkeeping cost component for A/C system scoring and recordkeeping. We recognize that this is somewhat more involved than reporting emissions test results, because A/C systems must be evaluated and scores calculated. We estimate that each air conditioning system evaluation and associated recordkeeping would take 30 minutes to 1 hour of managerial time, 1 to 2 hours of engineering time, and 15 to 30 minutes of secretarial time. We estimate one air conditioning system per every three vehicle models, or about 400 air conditioning systems across all light-duty vehicles. For chassis-certified heavy-duty vehicles, we've included an additional six systems, although systems may be the same across light-duty and heavy-duty vehicle models for individual manufacturers.

Using labor rate statistics from the Bureau of Labor Statistics for vehicle and engine manufacturers, with overhead 60% over the baseline applied (a multiplier of 1.6), we estimated reporting costs for each mobile source category.[9] For emissions reporting and recordkeeping, we used these labor rates, the estimated hours needed for reporting/recordkeeping for each vehicle/engine family as described above, and the number of vehicle and engine families estimated from EPA's certification databases, to calculate reporting costs. For vehicle air conditioning system reporting/recordkeeping costs, we used the labor rates, estimated hours needed for each air conditioning system, and the estimated number of air conditioning systems. The estimated number of vehicle/engine families and the average of the low and high estimates are provided in Table 4-77.

[9] May 2007 BLS National Industry-Specific Occupational Employment and Wage Estimates, labor rates for engineering managers, mechanical engineers, and secretaries (except legal, medical, and executives), NAICs code 336100 for vehicles and 333618 for engines. Vehicles: \$52.81, \$35.81, and \$19.53 for managerial, engineering, and secretarial hours, respectively. Engines: \$47.33, \$33.81, and \$15.86 for managerial, engineering, and secretarial hours, respectively.

Table 4-77. Mobile Source Vehicle and Engine Reporting/Recordkeeping Costs (2006$)

Category	Estimated Number of Vehicle/Engine Families	Estimated Average Annual Reporting/Record-Keeping Costs
Light-duty vehicles	3,062*	$197,000
Highway heavy-duty vehicles	17	$1,600
Highway heavy-duty engines	71	$2,800
Highway motorcycles	224	$8,700
Nonroad diesel engines	636	$25,000
Marine diesel engines	138	$5,400
Locomotives	59	$2,300
Nonroad small spark ignition engines	802	$31,000
Nonroad large spark ignition engines	31	$1,200
Marine spark ignition engines/personal watercraft	111	$4,300
Snowmobiles	37	$1,400
Off-highway motorcycles and ATVs	214	$8,300
Mobile sources	3,590	$289,000

* Includes 1,250 fuel economy and 1,812 in-use verification tests.

4.40.3 Equipment Costs: Test Equipment/Facility Upgrades

We have included estimated “start-up” capital costs associated with new test equipment for measuring N_20 and CH_4 for each affected test cell, except in cases where manufacturers already have this equipment. We estimated the number of test cells that would be affected in each category. For light-duty vehicles, the estimated number of test cells is based on certification data provided by manufacturers. For all other categories, where we do not have detailed test cell information for all manufacturers, we estimated one test cell for every six engine families certified for each manufacturer, based on our general understanding of certification testing and manufacturer test facilities.

We are including $50,000 per test cell for equipping the test cells with CH_4 measurement capabilities and $20,000 per test cell for N_20 measurement capabilities. These costs include the costs of the analyzers and related costs, including installation.

We have also estimated an incremental increased facility cost associated with the use of test facilities for running the proposed A/C CO_2 idle test for each vehicle test group. While we do not believe manufacturers will need significant new facilities to run the short idle test in conjunction with other emission testing, we believe it is reasonable to recognize that the new test could have incremental facility costs associated with it. No additional emissions measurement equipment is needed for vehicle A/C testing because manufacturers already have CO_2 measurement capabilities. Any costs would be associated with the additional time needed for the test.

We expect the A/C idle test to take less than 1 hour to run and it should fit into the testing sequence without significant disruption. To estimate incremental costs, we used a ratio of the time needed for the idle test (1 hour) with the time needed for certification testing (30 hours). We applied this ratio to an estimate of the facility costs per annual certification test. We estimate that a typical test facility is capable of performing 750 FTP/Highway fuel economy tests per year and the facility costs about $4 million to build, or about $5,333 per annual FTP test conducted. These estimates are based on EPA's experience working with manufacturers and test labs. Applying the ratio described above (1/30) to the annual test cost for an FTP results in an incremental facility cost estimate for the new A/C idle test of $178 per test. To estimate an overall facility cost, the $178 estimate was multiplied by the number of A/C idle tests per year, 1,250 for light-duty vehicles and 17 for heavy-duty vehicles. Manufacturers would likely be able to combine vehicle models into "air conditioning families," and conduct fewer than 1,250 tests for light-duty vehicles. However, it is unclear how many models could be grouped together, so we are including costs for all fuel economy tests. We also view these estimates as conservatively high because the test is not likely to take a full hour to run and the analysis assumes no excess test facility capacity currently exists for manufacturers.

There are no facilities or equipment costs associated with CO_2 because manufacturers already measure CO_2. This is also the case for CH_4 for light-duty vehicles, heavy-duty vehicles, and locomotives. Also, there are no facility or equipment costs associated with A/C system scoring (leakage evaluation), since this would be based on system components and design analysis rather than testing.

For each manufacturer, we have also included an estimated cost to account for information technology (IT) system modifications that may be needed to process the new emissions test data being collected. As mentioned above, the test data collection and processing is often highly automated. We have based the cost on 40 hours of IT staff time at $100 per hour for each manufacturer, except for light-duty manufacturers where we have estimated 80 hours of

IT staff time, due to the higher number of test cells per manufacturer and the need to process A/C data and information.

We have amortized the costs for the test facility and equipment upgrades described above over a 10-year recovery period using an amortization rate of 7% in our analysis. We believe that this approach reasonably accounts for the lifecycle of testing facilities and equipment. Also, these costs are projected to occur 1 year prior to the start of the program (manufacturers would need to install equipment and upgrade facilities ahead of and in preparation for the beginning of the reporting requirements) and the costs are adjusted using the 7% rate of return to reflect the time value of money. This methodology allows us to estimate an overall annualized cost, an average annual cost per manufacturer, and an average per vehicle or engine cost. Table 4-78 provides the estimated number of test cells and the total annualized facility costs for each mobile source category.

Table 4-78. Mobile Source Vehicle and Engine Annualized Equipment/Facility Costs (2006$)

Category	New Tests Proposed			Estimated Number of Test Cells	Estimated Average Annualized Equipment/Facility Costs
	CH_4	N_2O	A/C idle		
Light-duty vehicles		x	x	228	$890,000
Highway heavy-duty vehicles		x	x	3	$17,000
Highway heavy-duty engines	x	x		15	$187,000
Highway motorcycles	x	x		55	$699,000
Nonroad diesel engines	x	x		129	$1,537,000
Marine diesel engines	x	x		35	$439,000
Locomotives		x		11	$48,000
Nonroad small spark ignition engines	x	x		164	$1,946,000
Nonroad large spark ignition engines	x	x		9	$118,000
Marine spark ignition engines/personal watercraft	x	x		22	$264,000
Snowmobiles	x	x		7	$84,000
Off-highway motorcycles and ATVs	x	x		65	$820,000
Mobile sources				740	$7,048,000

4.40.4 O&M Costs: A/C Idle Test Operating Costs

For light-duty vehicle A/C CO_2 testing, manufacturers would incur a per test cost for the time necessary to conduct the new idle CO_2 test. This is in addition to the facility costs estimated above, and accounts for the operation and maintenance costs associated with running the test. We have added $60 per hour for each A/C idle test to account for operating costs, for a total annual cost of about $27,000 for light-duty vehicles and $1,000 for heavy-duty vehicles. There would be no additional O&M costs associated with other emissions measurements being proposed because these measurements would be done during tests already performed by manufacturers as part of current emissions testing requirements.

4.40.5 Total Aggregate Annualized Costs, and Average Per Manufacturer and Per Unit Costs

We estimated total annualized costs for each category and for mobile sources as a whole by summing the costs described above. We estimated per manufacturer average costs by dividing the annualized aggregate costs by the estimated number of manufacturers in each category, and per unit costs by dividing by the estimated annual sales for each category from the certification databases. Table 4-79 provides a summary of the costs described above and Table 4-80 provides the aggregate costs, average per manufacturer, and average per unit cost estimates. The aggregate costs by category vary depending primarily on the new requirements for each category, and the number of manufacturers, engine families, and test cells for each category. The costs are minimal relative to the typical costs for emissions certification. The total annualized cost for mobile sources is estimated to be about $7.4 million.

Table 4-79. Summary of Estimated Annual Mobile Source Costs by Category (2006$)

Category	Annual Labor[1]	Annualized IT Start-up	CO_2 O&M	CO_2 Annualized Capital/ Facility	N_2O O&M	N_2O Annualized Capital/ Equipment	CH_4 O&M	CH_4 Annualized Capital/ Equipment	A/C idle O&M	A/C idle Annualized Capital/ Facility	A/C System Score Annual Labor[2]
Light-duty vehicles	$133,000	$161,000	$0	$0	$0	$695,000	$0	$0	$75,000	$34,000	$64,000
Highway heavy-duty vehicles	$700	$7,300	$0	$0	$0	$9,100	$0	$0	$1,000	$500	$900
Highway heavy-duty engines	$2,800	$27,000	$0	$0	$0	$46,000	$0	$114,000	N/A	N/A	N/A
Highway motorcycles	$8,700	$112,000	$0	$0	$0	$168,000	$0	$419,000	N/A	N/A	N/A
Nonroad diesel engines	$25,000	$161,000	$0	$0	$0	$393,000	$0	$983,000	N/A	N/A	N/A
Marine diesel engines	$5,400	$66,000	$0	$0	$0	$107,000	$0	$267,000	N/A	N/A	N/A
Locomotives	$2,300	$15,000	$0	$0	$0	$34,000	$0	$0	N/A	N/A	N/A
Nonroad small spark ignition engines	$31,300	$197,000	$0	$0	$0	$500,000	$0	$1,249,000	N/A	N/A	N/A
Nonroad large spark ignition engines	$1,200	$22,000	$0	$0	$0	$27,000	$0	$69,000	N/A	N/A	N/A
Marine spark ignition engines/personal watercraft	$4,300	$29,000	$0	$0	$0	$67,000	$0	$168,000	N/A	N/A	N/A
Snowmobiles	$1,400	$2,800	$0	$0	$0	$21,000	$0	$53,000	N/A	N/A	N/A
Off-highway motorcycles and ATVs	$8,300	$127,000	$0	$0	$0	$198,000	$0	$495,000	N/A	N/A	N/A
Mobile sources	$224,100	$927,000	$0	$0	$0	$2,265,000	$0	$3,817,000	$76,000	$35,000	$65,000

[1] Includes annual labor costs associated with emissions test data reporting and recordkeeping for all pollutants.

[2] A/C system scoring would not involve testing and therefore costs are for reporting and recordkeeping only.

Table 4-80. Estimated Mobile Source Vehicle and Engine Annualized Aggregate Costs, Average Per Manufacturer Costs, and Average Per Unit Costs ($2006)

Category	Estimated Annualized Aggregate Costs	Estimated Average Per Manufacturer Costs	Estimated Average Per Unit Costs
Light-duty vehicles	$1,161,000	$35,000	$0.07
Highway heavy-duty vehicles	$20,000	$7,000	$0.06
Highway heavy-duty engines	$190,000	$17,000	$0.27
Highway motorcycles	$707,000	$15,000	$0.78
Nonroad diesel engines	$1,561,000	$18,000	$0.95
Marine diesel engines	$444,000	$16,000	$18.29
Locomotives	$50,000	$6,000	$10.96
Nonroad small spark ignition engines	$1,978,000	$24,000	$0.05
Nonroad large spark ignition engines	$119,000	$13,000	$1.09
Marine spark ignition engines/personal watercraft	$268,000	$22,000	$0.54
Snowmobiles	$86,000	$22,000	$0.87
Off-highway motorcycles and ATVs	$828,000	$16,000	$0.32
Mobile sources	$7,413,000		$0.12

4.41 Summary

Tables 4-81 and 4-82 present summary estimates of the impacts of the rule under the four thresholds. Table 4-81 shows, for each subpart at each threshold, the number and share of entities and emissions covered by the proposed rule. Table 4-82 summarizes the national costs and costs per representative entity for each subpart and each threshold.

As shown in Table 4-81, at lower thresholds a higher number and share of facilities and emissions are covered by the proposed rule. As the threshold increases, smaller numbers and shares of entities and emissions are affected. At the 1,000 MT threshold, half of the 40 subparts report that 100% of the entities and/or 100% of the emissions are covered. At this threshold, the median share of entities and emissions is 100%; however, the Manure Management subpart has fewer than 5% of entities covered—even at the lowest threshold—and less than 15% of emissions covered. At the proposed 25,000 MT threshold, on the other hand, only 17 subparts have 100% of entities covered, and only 13 subparts have 100% of emissions covered. The median share of entities covered has fallen to 92%, although the median share of emissions

Table 4-81. Number and Share of Entities and Emissions Covered by Threshold

Subpart	Implied Sectors	Number of Entities	Number of Entities Covered	Percent of Entities Covered	Total Emissions (Million MTCO2e/ Year)	Covered Emissions (Million MTCO2e/ Year)	Percent of Emissions Covered
1,000 Threshold							
C	Stationary Combustion	350,000	32,000	9%	410	250	61%
D	Electricity Generation		1,108		2,262	2,262	
E	Adipic Acid Production	4	4	100%	9	9	100%
F	Aluminum Production	14	14	100%	6	6	100%
G	Ammonia Manufacture and Urea Consumption	24	24	100%	15	15	100%
H	Cement Manufacture	107	107	100%	87	87	100%
I	Electronics	216	173	80%	6	6	100%
J	Ethanol Production	140	100	71%	NE	NE	
K	Ferroalloy Production	9	9	100%	2	2	100%
L	Fluorinated GHG Production	12	12	100%	5	5	100%
M	Food Processing	5,719	787	14%			
N	Glass	374	217	58%	4	4	98%
O	HCFC-22 Production & HFC Destruction	3	3	100%	14	14	100%
P	Hydrogen	77	73	95%	15	15	100%
Q	Iron and Steel Production	130	130	100%	85	85	100%
R	Lead Production	27	17	63%	1	1	99%
S	Lime Manufacture	89	89	100%	25	25	100%
T	Magnesium Production and Processing	13	13	100%	3	3	92%
U	Miscellaneous Uses of Carbonates				8	NA	
V	Nitric Acid Production	45	45	100%	18	18	100%
W	Oil & Natural Gas Systems	5,595	3,651	65%	149	149	100%
X	Petrochemical Production (325-ethylene, etc)	88	88	100%	55	55	100%
Y	Petroleum Refineries	150	150	100%	205	205	100%
Z	Phosphoric Acid Production	14	14	100%	4	4	100%
AA	Pulp & Paper	425	425	100%	58	58	100%
BB	Silicon Carbide Production and Consumption	1	1	100%	0	0	100%
CC	Soda Ash Manufacture and Consumption	5	5	100%	3	3	100%
DD	SF_6—Electrical Transmission and Distribution	1,364	578	42%	12	12	98%
EE	Titanium Dioxide Production	8	8	100%	4	4	100%
FF	Underground Coal Mines	612	125	20%	40	34	86%
GG	Zinc Production	9	9	100%	1	1	100%
HH	Landfills	7,800	6,830	88%	111	111	100%

(continued)

Table 4-81. Number and Share of Entities and Emissions Covered by Threshold (continued)

Subpart	Implied Sectors	Number of Entities	Number of Entities Covered	Percent of Entities Covered	Total Emissions (Million MTCO2e/ Year)	Covered Emissions (Million MTCO2e/ Year)	Percent of Emissions Covered
II	Wastewater Treatment						
JJ	Manure Management	329,304	9,049	3%	56	8	14%
KK, LL	Coal Mining & Suppliers	1,365	1,346	99%	2,153	2,146	100%
MM	Suppliers of Petroleum Products	364	359	99%	2,841	2,841	100%
NN	Suppliers of Natural Gas and Natural Gas Liquids	1,773	1,673	94%	797	797	100%
OO	Suppliers of Industrial GHGs	133	128	96%	465	465	100%
PP	Suppliers of Carbon Dioxide	13	13	100%	40	40	100%
QQ	Mobile Sources	NA	350		2,103	35	
10,000 Threshold							
C	Stationary Combustion	350,000	8,000	2%	410	230	56%
D	Electricity Generation		1,108		2,262	2,262	
E	Adipic Acid Production	4	4	100%	9	9	100%
F	Aluminum Production	14	14	100%	6	6	100%
G	Ammonia Manufacture and Urea Consumption	24	24	100%	15	15	100%
H	Cement Manufacture	107	107	100%	87	87	100%
I	Electronics	216	118	55%	6	6	98%
J	Ethanol Production	140	90	64%	NE	NE	
K	Ferroalloy Production	9	9	100%	2	2	100%
L	Fluorinated GHG Production	12	12	100%	5	5	100%
M	Food Processing	5,719	223	4%			
N	Glass	374	158	42%	4	4	91%
O	HCFC-22 Production & HFC Destruction	3	3	100%	14	14	100%
P	Hydrogen	77	51	66%	15	15	99%
Q	Iron and Steel Production	130	128	98%	85	85	100%
R	Lead Production	27	16	59%	1	1	98%
S	Lime Manufacture	89	89	100%	25	25	100%
T	Magnesium Production and Processing	13	11	85%	3	3	92%
U	Miscellaneous Uses of Carbonates				8	NA	
V	Nitric Acid Production	45	45	100%	18	18	100%
W	Oil & Natural Gas Systems	5,595	2,101	38%	149	142	95%
X	Petrochemical Production (325-ethylene, etc)	88	88	100%	55	55	100%
Y	Petroleum Refineries	150	150	100%	205	205	100%
Z	Phosphoric Acid Production	14	14	100%	4	4	100%

(continued)

Table 4-81. Number and Share of Entities and Emissions Covered by Threshold (continued)

Subpart	Implied Sectors	Number of Entities	Number of Entities Covered	Percent of Entities Covered	Total Emissions (Million MTCO2e/ Year)	Covered Emissions (Million MTCO2e/ Year)	Percent of Emissions Covered
AA	Pulp & Paper	425	425	100%	58	58	100%
BB	Silicon Carbide Production and Consumption	1	1	100%	0	0	100%
CC	Soda Ash Manufacture and Consumption	5	5	100%	3	3	100%
DD	SF_6—Electrical Transmission and Distribution	1,364	183	13%	12	11	88%
EE	Titanium Dioxide Production	8	8	100%	4	4	100%
FF	Underground Coal Mines	612	122	20%	40	34	86%
GG	Zinc Production	9	8	89%	1	1	99%
HH	Landfills	7,800	3,484	45%	111	104	94%
II	Wastewater Treatment						
JJ	Manure Management	329,304	445	0%	56	8	14%
KK, LL	Coal Mining & Suppliers	1,365	1,237	91%	2,153	2,146	100%
MM	Suppliers of Petroleum Products	364	333	91%	2,841	2,841	100%
NN	Suppliers of Natural Gas and Natural Gas Liquids	1,773	1,607	91%	797	795	100%
OO	Suppliers of Industrial GHGs	133	121	91%	465	464	100%
PP	Suppliers of Carbon Dioxide	13	13	100%	40	40	100%
QQ	Mobile Sources	NA	350		2,103	35	
25,000 Threshold							
C	Stationary Combustion	350,000	3,000	1%	410	220	54%
D	Electricity Generation		1,108		2,262	2,262	
E	Adipic Acid Production	4	4	100%	9	9	100%
F	Aluminum Production	14	14	100%	6	6	100%
G	Ammonia Manufacture and Urea Consumption	24	24	100%	15	15	100%
H	Cement Manufacture	107	107	100%	87	87	100%
I	Electronics	216	96	44%	6	6	95%
J	Ethanol Production	140	85	61%	NE	NE	
K	Ferroalloy Production	9	9	100%	2	2	100%
L	Fluorinated GHG Production	12	12	100%	5	5	100%
M	Food Processing	5,719	113	2%			
N	Glass	374	55	15%	4	2	51%
O	HCFC-22 Production & HFC Destruction	3	3	100%	14	14	100%
P	Hydrogen	77	41	53%	15	15	98%
Q	Iron and Steel Production	130	121	93%	85	85	100%

(continued)

Table 4-81. Number and Share of Entities and Emissions Covered by Threshold (continued)

Subpart	Implied Sectors	Number of Entities	Number of Entities Covered	Percent of Entities Covered	Total Emissions (Million MTCO2e/ Year)	Covered Emissions (Million MTCO2e/ Year)	Percent of Emissions Covered
R	Lead Production	27	13	48%	1	1	92%
S	Lime Manufacture	89	89	100%	25	25	100%
T	Magnesium Production and Processing	13	11	85%	3	3	92%
U	Miscellaneous Uses of Carbonates	—	—		8	NA	
V	Nitric Acid Production	45	45	100%	18	18	100%
W	Oil & Natural Gas Systems	5,595	1,375	25%	149	130	87%
X	Petrochemical Production (325-ethylene, etc)	88	88	100%	55	55	100%
Y	Petroleum Refineries	150	150	100%	205	205	100%
Z	Phosphoric Acid Production	14	14	100%	4	4	100%
AA	Pulp & Paper	425	425	100%	58	58	100%
BB	Silicon Carbide Production and Consumption	1	1	100%	0	0	100%
CC	Soda Ash Manufacture and Consumption	5	5	100%	3	3	100%
DD	SF_6—Electrical Transmission and Distribution	1,364	141	10%	12	10	83%
EE	Titanium Dioxide Production	8	8	100%	4	4	100%
FF	Underground Coal Mines	612	100	16%	40	34	85%
GG	Zinc Production	9	5	56%	1	1	94%
HH	Landfills	7,800	2,551	33%	111	91	82%
II	Wastewater Treatment						
JJ	Manure Management	329,304	43	0%	56	1	3%
KK, LL	Coal Mining & Suppliers	1,365	1,237	91%	2,153	2,144	100%
MM	Suppliers of Petroleum Products	364	214	59%	2,841	2,841	100%
NN	Suppliers of Natural Gas and Natural Gas Liquids	1,773	1,554	88%	797	791	99%
OO	Suppliers of Industrial GHGs	133	121	91%	465	464	100%
PP	Suppliers of Carbon Dioxide	13	13	100%	40	40	100%
QQ	Mobile Sources	NA	350		2,103	35	
100,000 Threshold							
C	Stationary Combustion	350,000	1,000	0%	410	170	41%
D	Electricity Generation		1,108		2,262	2,262	
E	Adipic Acid Production	4	4	100%	9	9	100%
F	Aluminum Production	14	13	93%	6	6	100%
G	Ammonia Manufacture and Urea Consumption	24	22	92%	15	14	99%

(continued)

Table 4-81. Number and Share of Entities and Emissions Covered by Threshold (continued)

Subpart	Implied Sectors	Number of Entities	Number of Entities Covered	Percent of Entities Covered	Total Emissions (Million MTCO2e/ Year)	Covered Emissions (Million MTCO2e/ Year)	Percent of Emissions Covered
H	Cement Manufacture	107	106	99%	87	87	100%
I	Electronics	216	54	25%	6	5	79%
J	Ethanol Production	140	40	29%	NE	NE	
K	Ferroalloy Production	9	8	89%	2	2	97%
L	Fluorinated GHG Production	12	9	75%	5	5	97%
M	Food Processing	5,719	11	0%			
N	Glass	374	1	0%	4	0	5%
O	HCFC-22 Production & HFC Destruction	3	3	100%	14	14	100%
P	Hydrogen	77	30	39%	15	14	94%
Q	Iron and Steel Production	130	111	85%	85	84	99%
R	Lead Production	27	—	0%	1	—	0%
S	Lime Manufacture	89	52	58%	25	24	94%
T	Magnesium Production and Processing	13	9	69%	3	3	90%
U	Miscellaneous Uses of Carbonates	—	—		8	NA	
V	Nitric Acid Production	45	40	89%	18	18	99%
W	Oil & Natural Gas Systems	5,595	387	7%	149	80	54%
X	Petrochemical Production (325-ethylene, etc)	88	84	95%	55	54	99%
Y	Petroleum Refineries	150	128	85%	205	204	100%
Z	Phosphoric Acid Production	14	14	100%	4	4	100%
AA	Pulp & Paper	425	410	96%	58	58	100%
BB	Silicon Carbide Production and Consumption	1	1	100%	0	0	100%
CC	Soda Ash Manufacture and Consumption	5	5	100%	3	3	100%
DD	SF_6—Electrical Transmission and Distribution	1,364	35	3%	12	6	48%
EE	Titanium Dioxide Production	8	7	88%	4	4	98%
FF	Underground Coal Mines	612	53	9%	40	31	79%
GG	Zinc Production	9	4	44%	1	1	84%
HH	Landfills	7,800	1,038	13%	111	66	59%
II	Wastewater Treatment						
JJ	Manure Management	329,304	—	0%	56	—	0%
KK, LL	Coal Mining & Suppliers	1,365	867	64%	2,153	2,130	99%
MM	Suppliers of Petroleum Products	364	214	59%	2,841	2,841	100%

(continued)

Table 4-81. Number and Share of Entities and Emissions Covered by Threshold (continued)

Subpart	Implied Sectors	Number of Entities	Number of Entities Covered	Percent of Entities Covered	Total Emissions (Million MTCO2e/ Year)	Covered Emissions (Million MTCO2e/ Year)	Percent of Emissions Covered
NN	Suppliers of Natural Gas and Natural Gas Liquids	1,773	450	25%	797	777	97%
OO	Suppliers of Industrial GHGs	133	61	46%	465	436	94%
PP	Suppliers of Carbon Dioxide	13	9	69%	40	39	100%
QQ	Mobile Sources	NA	350		2,103	35	

covered remains 100%. The manure management subpart again has the lowest share of entities covered (less than 1%) and only 3% of emissions covered. At the highest threshold (100,000 MT), only five subparts have 100% of entities covered and only six subparts have 100% of emissions covered. At this threshold, five subparts have less than 1% of entities covered. The median share of entities covered has fallen to 66%, but the median share of emissions covered remains high at 98%.

Table 4-82 presents the costs of compliance for each subpart at each threshold. The first eight columns report subsets of costs, including costs associated with processes (labor, annualized capital, and operating and maintenance costs), costs associated with wastewater treatment, costs associated with landfills, costs associated with reporting electricity usage, costs associated with reporting and recordkeeping, and costs associated with stationary combustion. The final four columns report total national costs and total per-entity costs for the first year and for subsequent years. (Because the first year entails added compliance activities, relative to subsequent years, many subparts have higher costs in the first year relative to subsequent years). As described in Table 4-81, at lower thresholds, a larger number of entities in each subpart are covered by the proposed rule, and thus incur costs. For this reason, the total national costs, and total costs by cost subset, decline as the threshold increases from 1,000 MT to 10,000 MT, to 25,000 MT, and finally to 100,000 MT. First year national costs, for example, range from $426 million at the 1,000 MT threshold, to $218 million at the 10,000 MT threshold, to $160 million at the 25,000 MT threshold, to $101 million at the 100,000 MT threshold. Cost per representative entity for a particular subpart generally remains the same or declines slightly from lower thresholds to higher ones; however, it varies considerably from subpart to subpart.

Table 4-82. Summary of Costs and Costs per Representative Entity by Threshold (Million $2006)

Subpart	Implied Sectors	First Year Process Costs	Subsequent Year Process Costs	Reporting and Recordkeeping Costs	Electricity Use Costs	Wastewater Treatment Costs	First Year Landfill Costs	Subsequent Year Landfill Costs	First Year Combustion Costs	Second Year Combustion Costs	First Year National Costs	First Year Representative Entity Cost	Subsequent Year National Costs	Subsequent Year Representative Entity Cost
Threshold: 1,000														
C	Stationary Combustion	0.000	0.000	0.000	0.949	0.000	0.000	0.000	188.771	183.991	189.720	0.006	184.940	0.006
D	Electricity Generation	0.000	0.000	0.000	0.033	0.000	0.000	0.000	3.279	3.279	3.312	0.003	3.312	0.003
E	Adipic Acid Production	0.038	0.033	0.009	0.000	0.000	0.000	0.000	0.049	0.033	0.096	0.024	0.075	0.019
F	Aluminum Production	0.314	0.314	0.024	0.000	0.000	0.000	0.000	0.105	0.105	0.443	0.032	0.443	0.032
G	Ammonia Manufacture and Urea Consumption	0.098	0.070	0.053	0.001	0.000	0.000	0.000	0.296	0.197	0.447	0.019	0.321	0.013
H	Cement Manufacture	0.989	0.817	0.235	0.003	0.000	0.000	0.000	5.701	3.217	6.928	0.065	4.273	0.040
I	Electronics	3.773	3.773	0.294	0.005	0.000	0.000	0.000	0.699	0.699	4.771	0.028	4.771	0.028
J	Ethanol Production	0.252	0.252	0.220	0.003	0.000	0.000	0.000	0.000	0.000	0.475	0.005	0.475	0.005
K	Ferroalloy Production	0.195	0.180	0.020	0.000	0.000	0.000	0.000	0.040	0.029	0.255	0.028	0.229	0.025
L	Fluorinated GHG Production	0.003	0.003	0.026	0.000	0.000	0.000	0.000	0.000	0.000	0.030	0.002	0.030	0.002
M	Food Processing	0.000	0.000	1.731	0.023	1.634	0.575	0.209	0.000	0.000	3.964	0.005	3.597	0.005
N	Glass	0.348	0.112	0.477	0.006	0.000	0.000	0.000	1.453	1.056	2.285	0.011	1.651	0.008
O	HCFC-22 Production & HFC Destruction	0.017	0.017	0.007	0.000	0.000	0.000	0.000	0.000	0.000	0.023	0.008	0.023	0.008
P	Hydrogen	0.242	0.122	0.161	0.002	0.000	0.000	0.000	0.516	0.375	0.920	0.013	0.659	0.009
Q	Iron and Steel Production	19.262	14.899	0.286	0.004	0.000	0.000	0.000	0.000	0.000	19.552	0.150	15.189	0.117
R	Lead Production	0.231	0.207	0.037	0.001	0.000	0.000	0.000	0.114	0.083	0.383	0.023	0.328	0.019
S	Lime Manufacture	0.138	0.041	0.196	0.003	0.000	0.000	0.000	4.988	2.788	5.324	0.060	3.028	0.034
T	Magnesium Production and Processing	0.037	0.037	0.029	0.000	0.000	0.000	0.000	0.061	0.061	0.126	0.010	0.126	0.010
U	Miscellaneous Uses of Carbonates	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	

(continued)

Table 4-82. Summary of Costs and Costs per Representative Entity by Threshold (Million $2006) (continued)

Subpart	Implied Sectors	First Year Process Costs	Subsequent Year Process Costs	Reporting and Recordkeeping Costs	Electricity Use Costs	Wastewater Treatment Costs	First Year Landfill Costs	Subsequent Year Landfill Costs	First Year Combustion Costs	Second Year Combustion Costs	First Year National Costs	First Year Representative Entity Cost	Subsequent Year National Costs	Subsequent Year Representative Entity Cost
V	Nitric Acid Production	0.567	0.517	0.099	0.001	0.000	0.000	0.000	0.224	0.125	0.891	0.020	0.743	0.017
W	Oil & Natural Gas Systems	54.971	44.430	8.032	0.108	0.000	0.000	0.000	0.000	0.000	63.112	0.017	52.570	0.014
X	Petrochemical Production (325-ethylene, etc)	1.643	1.289	0.000	0.003	0.000	0.000	0.000	0.000	0.000	1.646	0.019	1.292	0.015
Y	Petroleum Refineries	3.113	2.250	0.255	0.004	0.280	0.000	0.000	0.000	0.000	3.652	0.024	2.789	0.019
Z	Phosphoric Acid Production	0.022	0.006	0.031	0.000	0.000	0.000	0.000	0.785	0.439	0.838	0.060	0.476	0.034
AA	Pulp & Paper	7.705	7.705	0.935	0.013	0.198	0.548	0.199	0.000	0.000	9.399	0.022	9.050	0.021
BB	Silicon Carbide Production and Consumption	0.003	0.002	0.002	0.000	0.000	0.000	0.000	0.006	0.006	0.011	0.011	0.009	0.009
CC	Soda Ash Manufacture and Consumption	0.008	0.002	0.011	0.000	0.000	0.000	0.000	0.028	0.028	0.046	0.009	0.041	0.008
DD	SF_6—Electrical Transmission and Distribution	1.279	1.279	0.289	0.017	0.000	0.000	0.000	0.000	0.000	1.585	0.003	1.585	0.003
EE	Titanium Dioxide Production	0.012	0.004	0.018	0.000	0.000	0.000	0.000	0.044	0.044	0.074	0.009	0.066	0.008
FF	Underground Coal Mines	2.603	2.583	0.275	0.000	0.000	0.000	0.000	0.000	0.000	2.878	0.023	2.858	0.023
GG	Zinc Production	0.050	0.039	0.020	0.000	0.000	0.000	0.000	0.060	0.044	0.130	0.014	0.103	0.011
HH	Landfills	24.002	10.756	11.611	0.203	0.000	0.000	0.000	0.000	0.000	35.815	0.005	22.569	0.003
II	Wastewater Treatment	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
JJ	Manure Management	22.364	17.795	19.908	0.268	0.000	0.000	0.000	0.000	0.000	42.540	0.005	37.971	0.004
KK, LL	Coal Mining & Suppliers	11.286	5.500	0.000	0.040	0.000	0.000	0.000	0.000	0.000	11.326	0.008	5.540	0.004
MM	Suppliers of Petroleum Products	3.065	1.204	0.000	0.000	0.000	0.000	0.000	0.000	0.000	3.065	0.009	1.204	0.003
NN	Suppliers of Natural Gas and Natural Gas Liquids	2.303	1.416	0.000	0.050	0.000	0.000	0.000	0.000	0.000	2.353	0.001	1.465	0.001

(continued)

Table 4-82. Summary of Costs and Costs per Representative Entity by Threshold (Million $2006) (continued)

Subpart	Implied Sectors	First Year Process Costs	Subsequent Year Process Costs	Reporting and Recordkeeping Costs	Electricity Use Costs	Wastewater Treatment Costs	First Year Landfill Costs	Subsequent Year Landfill Costs	First Year Combustion Costs	Second Year Combustion Costs	First Year National Costs	First Year Representative Entity Cost	Subsequent Year National Costs	Subsequent Year Representative Entity Cost
OO	Suppliers of Industrial GHGs	0.117	0.117	0.282	0.004	0.000	0.000	0.000	0.000	0.000	0.402	0.003	0.402	0.003
PP	Suppliers of Carbon Dioxide	0.003	0.003	0.029	0.000	0.000	0.000	0.000	0.000	0.000	0.032	0.002	0.032	0.002
QQ	Mobile Sources	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	7.413	0.021	7.413	0.021
Total		161.054	117.774	45.601	1.746	2.112	1.123	0.407	207.216	196.595	426.265		371.649	
Threshold: 10,000														
C	Stationary Combustion	0.000	0.000	0.000	0.237	0.000	0.000	0.000	56.628	51.916	56.865	0.007	52.153	0.007
D	Electricity Generation	0.000	0.000	0.000	0.033	0.000	0.000	0.000	3.279	3.279	3.312	0.003	3.312	0.003
E	Adipic Acid Production	0.038	0.033	0.009	0.000	0.000	0.000	0.000	0.049	0.033	0.096	0.024	0.075	0.019
F	Aluminum Production	0.314	0.314	0.024	0.000	0.000	0.000	0.000	0.105	0.105	0.443	0.032	0.443	0.032
G	Ammonia Manufacture and Urea Consumption	0.098	0.070	0.053	0.001	0.000	0.000	0.000	0.296	0.197	0.447	0.019	0.321	0.013
H	Cement Manufacture	0.989	0.817	0.235	0.003	0.000	0.000	0.000	5.701	3.217	6.928	0.065	4.273	0.040
I	Electronics	3.111	3.111	0.201	0.003	0.000	0.000	0.000	0.699	0.699	4.014	0.034	4.014	0.034
J	Ethanol Production	0.227	0.227	0.198	0.003	0.000	0.000	0.000	0.000	0.000	0.428	0.005	0.428	0.005
K	Ferroalloy Production	0.195	0.180	0.020	0.000	0.000	0.000	0.000	0.040	0.029	0.255	0.028	0.229	0.025
L	Fluorinated GHG Production	0.003	0.003	0.026	0.000	0.000	0.000	0.000	0.000	0.000	0.030	0.002	0.030	0.002
M	Food Processing	0.000	0.000	0.491	0.007	0.217	0.517	0.188	0.000	0.000	1.231	0.006	0.902	0.004
N	Glass	0.253	0.081	0.348	0.005	0.000	0.000	0.000	1.058	0.769	1.663	0.011	1.202	0.008
O	HCFC-22 Production & HFC Destruction	0.017	0.017	0.007	0.000	0.000	0.000	0.000	0.000	0.000	0.023	0.008	0.023	0.008
P	Hydrogen	0.169	0.085	0.112	0.002	0.000	0.000	0.000	0.489	0.355	0.772	0.015	0.554	0.011
Q	Iron and Steel Production	18.966	14.670	0.282	0.004	0.000	0.000	0.000	0.000	0.000	19.251	0.150	14.955	0.117

(continued)

Table 4-82. Summary of Costs and Costs per Representative Entity by Threshold (Million $2006) (continued)

Subpart	Implied Sectors	First Year Process Costs	Subsequent Year Process Costs	Reporting and Recordkeeping Costs	Electricity Use Costs	Wastewater Treatment Costs	First Year Landfill Costs	Subsequent Year Landfill Costs	First Year Combustion Costs	Second Year Combustion Costs	First Year National Costs	First Year Representative Entity Cost	Subsequent Year National Costs	Subsequent Year Representative Entity Cost
R	Lead Production	0.217	0.195	0.035	0.000	0.000	0.000	0.000	0.107	0.078	0.360	0.023	0.308	0.019
S	Lime Manufacture	0.138	0.041	0.196	0.003	0.000	0.000	0.000	4.988	2.788	5.324	0.060	3.028	0.034
T	Magnesium Production and Processing	0.031	0.031	0.024	0.000	0.000	0.000	0.000	0.061	0.061	0.116	0.011	0.116	0.011
U	Miscellaneous Uses of Carbonates	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	
V	Nitric Acid Production	0.567	0.517	0.099	0.001	0.000	0.000	0.000	0.224	0.125	0.891	0.020	0.743	0.017
W	Oil & Natural Gas Systems	41.221	34.418	4.622	0.062	0.000	0.000	0.000	0.000	0.000	45.906	0.022	39.102	0.019
X	Petrochemical Production (325-ethylene, etc)	1.643	1.289	0.000	0.003	0.000	0.000	0.000	0.000	0.000	1.646	0.019	1.292	0.015
Y	Petroleum Refineries	3.113	2.250	0.255	0.004	0.280	0.000	0.000	0.000	0.000	3.652	0.024	2.789	0.019
Z	Phosphoric Acid Production	0.022	0.006	0.031	0.000	0.000	0.000	0.000	0.785	0.439	0.838	0.060	0.476	0.034
AA	Pulp & Paper	7.705	7.705	0.935	0.013	0.198	0.517	0.188	0.000	0.000	9.369	0.022	9.039	0.021
BB	Silicon Carbide Production and Consumption	0.003	0.002	0.002	0.000	0.000	0.000	0.000	0.006	0.006	0.011	0.011	0.009	0.009
CC	Soda Ash Manufacture and Consumption	0.008	0.002	0.011	0.000	0.000	0.000	0.000	0.028	0.028	0.046	0.009	0.041	0.008
DD	SF_6—Electrical Transmission and Distribution	0.405	0.405	0.092	0.005	0.000	0.000	0.000	0.000	0.000	0.502	0.003	0.502	0.003
EE	Titanium Dioxide Production	0.012	0.004	0.018	0.000	0.000	0.000	0.000	0.044	0.044	0.074	0.009	0.066	0.008
FF	Underground Coal Mines	2.546	2.525	0.268	0.000	0.000	0.000	0.000	0.000	0.000	2.815	0.023	2.794	0.023
GG	Zinc Production	0.045	0.035	0.018	0.000	0.000	0.000	0.000	0.060	0.044	0.123	0.015	0.097	0.012
HH	Landfills	13.819	7.062	5.923	0.103	0.000	0.000	0.000	0.000	0.000	19.846	0.006	13.089	0.004
II	Wastewater Treatment	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
JJ	Manure Management	1.100	0.875	0.979	0.013	0.000	0.000	0.000	0.000	0.000	2.092	0.005	1.867	0.004

(continued)

Table 4-82. Summary of Costs and Costs per Representative Entity by Threshold (Million $2006) (continued)

Subpart	Implied Sectors	First Year Process Costs	Subsequent Year Process Costs	Reporting and Recordkeeping Costs	Electricity Use Costs	Wastewater Treatment Costs	First Year Landfill Costs	Subsequent Year Landfill Costs	First Year Combustion Costs	Second Year Combustion Costs	First Year National Costs	First Year Representative Entity Cost	Subsequent Year National Costs	Subsequent Year Representative Entity Cost
KK, LL	Coal Mining & Suppliers	10.990	5.371	0.000	0.037	0.000	0.000	0.000	0.000	0.000	11.027	0.009	5.408	0.004
MM	Suppliers of Petroleum Products	2.873	1.124	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2.873	0.009	1.124	0.003
NN	Suppliers of Natural Gas and Natural Gas Liquids	2.188	1.333	0.000	0.048	0.000	0.000	0.000	0.000	0.000	2.236	0.001	1.380	0.001
OO	Suppliers of Industrial GHGs	0.110	0.110	0.266	0.004	0.000	0.000	0.000	0.000	0.000	0.380	0.003	0.380	0.003
PP	Suppliers of Carbon Dioxide	0.003	0.003	0.029	0.000	0.000	0.000	0.000	0.000	0.000	0.032	0.002	0.032	0.002
QQ	Mobile Sources	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	7.413	0.021	7.413	0.021
Total		113.139	84.913	15.806	0.596	0.695	1.035	0.375	74.644	64.209	213.328		174.007	
Threshold: 25,000														
C	Stationary Combustion	0.000	0.000	0.000	0.089	0.000	0.000	0.000	28.885	24.292	28.974	0.010	24.381	0.008
D	Electricity Generation	0.000	0.000	0.000	0.033	0.000	0.000	0.000	3.279	3.279	3.312	0.003	3.312	0.003
E	Adipic Acid Production	0.038	0.033	0.009	0.000	0.000	0.000	0.000	0.049	0.033	0.096	0.024	0.075	0.019
F	Aluminum Production	0.314	0.314	0.024	0.000	0.000	0.000	0.000	0.105	0.105	0.443	0.032	0.443	0.032
G	Ammonia Manufacture and Urea Consumption	0.098	0.070	0.053	0.001	0.000	0.000	0.000	0.296	0.197	0.447	0.019	0.321	0.013
H	Cement Manufacture	0.989	0.817	0.235	0.003	0.000	0.000	0.000	5.701	3.217	6.928	0.065	4.273	0.040
I	Electronics	2.728	2.728	0.163	0.003	0.000	0.000	0.000	0.699	0.699	3.593	0.037	3.593	0.037
J	Ethanol Production	0.271	0.271	0.187	0.003	0.000	0.000	0.000	0.000	0.000	0.460	0.005	0.460	0.005
K	Ferroalloy Production	0.195	0.180	0.020	0.000	0.000	0.000	0.000	0.040	0.029	0.255	0.028	0.229	0.025
L	Fluorinated GHG Production	0.003	0.003	0.026	0.000	0.000	0.000	0.000	0.000	0.000	0.030	0.002	0.030	0.002
M	Food Processing	0.000	0.000	0.249	0.003	0.036	0.304	0.110	0.000	0.000	0.592	0.005	0.398	0.004
N	Glass	0.088	0.028	0.121	0.002	0.000	0.000	0.000	0.368	0.268	0.579	0.011	0.418	0.008
O	HCFC-22 Production & HFC Destruction	0.017	0.017	0.007	0.000	0.000	0.000	0.000	0.000	0.000	0.023	0.008	0.023	0.008

(continued)

Table 4-82. Summary of Costs and Costs per Representative Entity by Threshold (Million $2006) (continued)

Subpart	Implied Sectors	First Year Process Costs	Subsequent Year Process Costs	Reporting and Recordkeeping Costs	Electricity Use Costs	Wastewater Treatment Costs	First Year Landfill Costs	Subsequent Year Landfill Costs	First Year Combustion Costs	Second Year Combustion Costs	First Year National Costs	First Year Representative Entity Cost	Subsequent Year National Costs	Subsequent Year Representative Entity Cost
P	Hydrogen	0.136	0.069	0.090	0.001	0.000	0.000	0.000	0.341	0.248	0.569	0.014	0.408	0.010
Q	Iron and Steel Production	17.929	13.868	0.266	0.004	0.000	0.000	0.000	0.000	0.000	18.198	0.150	14.137	0.117
R	Lead Production	0.177	0.158	0.029	0.000	0.000	0.000	0.000	0.087	0.063	0.293	0.023	0.250	0.019
S	Lime Manufacture	0.138	0.041	0.196	0.003	0.000	0.000	0.000	4.988	2.788	5.324	0.060	3.028	0.034
T	Magnesium Production and Processing	0.031	0.031	0.024	0.000	0.000	0.000	0.000	0.061	0.061	0.116	0.011	0.116	0.011
U	Miscellaneous Uses of Carbonates	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	
V	Nitric Acid Production	0.567	0.517	0.099	0.001	0.000	0.000	0.000	0.224	0.125	0.891	0.020	0.743	0.017
W	Oil & Natural Gas Systems	29.444	25.056	3.025	0.041	0.000	0.000	0.000	0.000	0.000	32.510	0.024	28.122	0.020
X	Petrochemical Production (325-ethylene, etc)	1.643	1.289	0.000	0.003	0.000	0.000	0.000	0.000	0.000	1.646	0.019	1.292	0.015
Y	Petroleum Refineries	3.113	2.250	0.255	0.004	0.280	0.000	0.000	0.000	0.000	3.652	0.024	2.789	0.019
Z	Phosphoric Acid Production	0.022	0.006	0.031	0.000	0.000	0.000	0.000	0.785	0.439	0.838	0.060	0.476	0.034
AA	Pulp & Paper	7.705	7.705	0.935	0.013	0.198	0.304	0.110	0.000	0.000	9.156	0.022	8.962	0.021
BB	Silicon Carbide Production and Consumption	0.003	0.002	0.002	0.000	0.000	0.000	0.000	0.006	0.006	0.011	0.011	0.009	0.009
CC	Soda Ash Manufacture and Consumption	0.008	0.002	0.011	0.000	0.000	0.000	0.000	0.028	0.028	0.046	0.009	0.041	0.008
DD	SF_6—Electrical Transmission and Distribution	0.312	0.312	0.071	0.004	0.000	0.000	0.000	0.000	0.000	0.387	0.003	0.387	0.003
EE	Titanium Dioxide Production	0.012	0.004	0.018	0.000	0.000	0.000	0.000	0.044	0.044	0.074	0.009	0.066	0.008
FF	Underground Coal Mines	2.127	2.106	0.220	0.000	0.000	0.000	0.000	0.000	0.000	2.347	0.023	2.326	0.023
GG	Zinc Production	0.028	0.022	0.011	0.000	0.000	0.000	0.000	0.054	0.039	0.093	0.019	0.072	0.014
HH	Landfills	10.923	5.975	4.337	0.076	0.000	0.000	0.000	0.000	0.000	15.335	0.006	10.388	0.004
II	Wastewater Treatment	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	
JJ	Manure Management	0.107	0.086	0.095	0.001	0.000	0.000	0.000	0.000	0.000	0.203	0.005	0.181	0.004

(continued)

Table 4-82. Summary of Costs and Costs per Representative Entity by Threshold (Million $2006) (continued)

Subpart	Implied Sectors	First Year Process Costs	Subsequent Year Process Costs	Reporting and Recordkeeping Costs	Electricity Use Costs	Wastewater Treatment Costs	First Year Landfill Costs	Subsequent Year Landfill Costs	First Year Combustion Costs	Second Year Combustion Costs	First Year National Costs	First Year Representative Entity Cost	Subsequent Year National Costs	Subsequent Year Representative Entity Cost
KK, LL	Coal Mining & Suppliers	10.990	5.371	0.000	0.037	0.000	0.000	0.000	0.000	0.000	11.027	0.009	5.408	0.004
MM	Suppliers of Petroleum Products	1.991	0.756	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.991	0.009	0.756	0.004
NN	Suppliers of Natural Gas and Natural Gas Liquids	2.096	1.266	0.000	0.046	0.000	0.000	0.000	0.000	0.000	2.142	0.001	1.312	0.001
OO	Suppliers of Industrial GHGs	0.110	0.110	0.266	0.004	0.000	0.000	0.000	0.000	0.000	0.380	0.003	0.380	0.003
PP	Suppliers of Carbon Dioxide	0.003	0.003	0.029	0.000	0.000	0.000	0.000	0.000	0.000	0.032	0.002	0.032	0.002
QQ	Mobile Sources	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	7.413	0.021	7.413	0.021
Total		**94.354**	**71.466**	**11.102**	**0.376**	**0.514**	**0.609**	**0.221**	**46.037**	**35.957**	**160.405**		**127.049**	
Threshold 100,000														
C	Stationary Combustion	0.000	0.000	0.000	0.030	0.000	0.000	0.000	10.328	7.520	10.358	0.010	7.550	0.008
D	Electricity Generation	0.000	0.000	0.000	0.033	0.000	0.000	0.000	3.279	3.279	3.312	0.003	3.312	0.003
E	Adipic Acid Production	0.038	0.033	0.009	0.000	0.000	0.000	0.000	0.049	0.033	0.096	0.024	0.075	0.019
F	Aluminum Production	0.292	0.292	0.022	0.000	0.000	0.000	0.000	0.105	0.105	0.419	0.032	0.419	0.032
G	Ammonia Manufacture and Urea Consumption	0.090	0.065	0.048	0.001	0.000	0.000	0.000	0.296	0.197	0.435	0.020	0.310	0.014
H	Cement Manufacture	0.980	0.809	0.233	0.003	0.000	0.000	0.000	5.701	3.217	6.917	0.065	4.263	0.040
I	Electronics	1.971	1.971	0.092	0.002	0.000	0.000	0.000	0.699	0.699	2.763	0.051	2.763	0.051
J	Ethanol Production	0.127	0.127	0.088	0.001	0.000	0.000	0.000	0.000	0.000	0.216	0.005	0.216	0.005
K	Ferroalloy Production	0.173	0.160	0.018	0.000	0.000	0.000	0.000	0.040	0.029	0.231	0.029	0.207	0.026
L	Fluorinated GHG Production	0.002	0.002	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.022	0.002	0.022	0.002
M	Food Processing	0.000	0.000	0.024	0.000	0.003	0.030	0.011	0.000	0.000	0.058	0.005	0.039	0.004
N	Glass	0.002	0.001	0.002	0.000	0.000	0.000	0.000	0.007	0.005	0.011	0.011	0.008	0.008
O	HCFC-22 Production & HFC Destruction	0.017	0.017	0.007	0.000	0.000	0.000	0.000	0.000	0.000	0.023	0.008	0.023	0.008

(continued)

Table 4-82. Summary of Costs and Costs per Representative Entity by Threshold (Million $2006) (continued)

Subpart	Implied Sectors	First Year Process Costs	Subsequent Year Process Costs	Reporting and Recordkeeping Costs	Electricity Use Costs	Wastewater Treatment Costs	First Year Landfill Costs	Subsequent Year Landfill Costs	First Year Combustion Costs	Second Year Combustion Costs	First Year National Costs	First Year Representative Entity Cost	Subsequent Year National Costs	Subsequent Year Representative Entity Cost
P	Hydrogen	0.099	0.050	0.066	0.001	0.000	0.000	0.000	0.201	0.146	0.367	0.012	0.263	0.009
Q	Iron and Steel Production	16.447	12.722	0.244	0.003	0.000	0.000	0.000	0.000	0.000	16.694	0.150	12.969	0.117
R	Lead Production	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	
S	Lime Manufacture	0.081	0.024	0.114	0.002	0.000	0.000	0.000	4.988	2.788	5.184	0.100	2.928	0.056
T	Magnesium Production and Processing	0.025	0.025	0.020	0.000	0.000	0.000	0.000	0.061	0.061	0.106	0.012	0.106	0.012
U	Miscellaneous Uses of Carbonates	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	
V	Nitric Acid Production	0.504	0.460	0.088	0.001	0.000	0.000	0.000	0.224	0.125	0.817	0.020	0.674	0.017
W	Oil & Natural Gas Systems	9.816	8.849	0.851	0.011	0.000	0.000	0.000	0.000	0.000	10.679	0.028	9.712	0.025
X	Petrochemical Production (325-ethylene, etc)	1.569	1.230	0.000	0.002	0.000	0.000	0.000	0.000	0.000	1.571	0.019	1.233	0.015
Y	Petroleum Refineries	2.656	1.920	0.218	0.004	0.239	0.000	0.000	0.000	0.000	3.117	0.024	2.380	0.019
Z	Phosphoric Acid Production	0.022	0.006	0.031	0.000	0.000	0.000	0.000	0.785	0.439	0.838	0.060	0.476	0.034
AA	Pulp & Paper	7.433	7.433	0.902	0.012	0.191	0.030	0.011	0.000	0.000	8.569	0.021	8.550	0.021
BB	Silicon Carbide Production and Consumption	0.003	0.002	0.002	0.000	0.000	0.000	0.000	0.006	0.006	0.011	0.011	0.009	0.009
CC	Soda Ash Manufacture and Consumption	0.008	0.002	0.011	0.000	0.000	0.000	0.000	0.028	0.028	0.046	0.009	0.041	0.008
DD	SF_6—Electrical Transmission and Distribution	0.077	0.077	0.018	0.001	0.000	0.000	0.000	0.000	0.000	0.096	0.003	0.096	0.003
EE	Titanium Dioxide Production	0.011	0.003	0.015	0.000	0.000	0.000	0.000	0.044	0.044	0.070	0.010	0.063	0.009
FF	Underground Coal Mines	1.231	1.210	0.117	0.000	0.000	0.000	0.000	0.000	0.000	1.347	0.025	1.327	0.025
GG	Zinc Production	0.022	0.017	0.009	0.000	0.000	0.000	0.000	0.033	0.024	0.065	0.016	0.051	0.013
HH	Landfills	4.925	2.912	1.765	0.031	0.000	0.000	0.000	0.000	0.000	6.721	0.006	4.708	0.005
II	Wastewater Treatment	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	
JJ	Manure Management	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	

(continued)

Table 4-82. Summary of Costs and Costs per Representative Entity by Threshold (Million $2006) (continued)

Subpart	Implied Sectors	First Year Process Costs	Subsequent Year Process Costs	Reporting and Recordkeeping Costs	Electricity Use Costs	Wastewater Treatment Costs	First Year Landfill Costs	Subsequent Year Landfill Costs	First Year Combustion Costs	Second Year Combustion Costs	First Year National Costs	First Year Representative Entity Cost	Subsequent Year National Costs	Subsequent Year Representative Entity Cost
KK, LL	Coal Mining & Suppliers	9.983	4.931	0.000	0.026	0.000	0.000	0.000	0.000	0.000	10.009	0.012	4.957	0.006
MM	Suppliers of Petroleum Products	1.991	0.756	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.991	0.009	0.756	0.004
NN	Suppliers of Natural Gas and Natural Gas Liquids	0.680	0.448	0.000	0.013	0.000	0.000	0.000	0.000	0.000	0.693	0.002	0.462	0.001
OO	Suppliers of Industrial GHGs	0.053	0.053	0.134	0.002	0.000	0.000	0.000	0.000	0.000	0.189	0.003	0.189	0.003
PP	Suppliers of Carbon Dioxide	0.002	0.002	0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.022	0.002	0.022	0.002
QQ	Mobile Sources	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	7.413	0.021	7.413	0.021
Total		**61.330**	**46.611**	**5.187**	**0.181**	**0.433**	**0.061**	**0.022**	**26.871**	**18.743**	**101.476**		**78.591**	

Across thresholds, some subsets of costs are typically larger (process, combustion) compared to other subsets (electricity usage, reporting and recordkeeping). Entities in some subparts incur higher costs relative to other subparts, regardless of the threshold. The subparts incurring higher costs of compliance in general are stationary combustion, pulp and paper manufacturing, iron and steel manufacturing, and oil and natural gas systems.

4.42 References

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SECTION 5
ECONOMY-WIDE ANALYSIS OF REPORTING RULE OPTIONS

In 2006, the total estimated U.S. GHG emissions as reported in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2006* are 7.1 billion $MtCO_2e$. As shown in Table 5-1, the total national emissions covered under the recommended option are 3.9 billion $MtCO_2e$. The majority of these covered emissions are from the electricity generation units covered by ARP (2.3 billion $MtCO_2e$). Adding upstream fuel suppliers emissions would increase this estimate by approximately 30% but would also double-count an unknown fraction of downstream emissions.[10]

[10]While the fraction of overlap is unknown, it is estimated in Section 5.1.7.

Table 5-1. Estimates of Emissions ($MtCO_2e$) Reported in 2006 Under the Recommended Option

Sector	Quantity
Subpart A—General Provisions	
Subpart B—Electricity Use	
Subpart C—General Stationary Fuel Combustion Sources	220.0
Subpart D—Electricity Generation	2262.0
Subpart E—Adipic Acid Production	9.3
Subpart F—Aluminum Production	6.4
Subpart G—Ammonia Manufacturing	14.5
Subpart H—Cement Production	86.8
Subpart I—Electronics Manufacturing	5.7
Subpart J—Ethanol Production	
Subpart K—Ferroalloy Production	2.3
Subpart L—Fluorinated Gas Production	5.3
Subpart M—Food Processing	0.0
Subpart N—Glass Production	2.2
Subpart O—HCFC-22 Production	13.8
Subpart P—Hydrogen Production	15.0
Subpart Q—Iron and Steel Production	85.0
Subpart R—Lead Production	0.8
Subpart S—Lime Manufacturing	25.4
Subpart T—Magnesium Production	2.9
Subpart U—Miscellaneous Uses of Carbonates	
Subpart V—Nitric Acid Production	17.7
Subpart W—Oil and Natural Gas Systems	129.9
Subpart X—Petrochemical Production	54.8
Subpart Y—Petroleum Refineries	204.7
Subpart Z—Phosphoric Acid Production	3.8
Subpart AA—Pulp and Paper Manufacturing	57.7
Subpart BB—Silicon Carbide Production	0.1
Subpart CC—Soda Ash Manufacturing	3.1
Subpart DD—Sulfur Hexafluoride (SF6) from Electric Power Systems	10.3
Subpart EE—Titanium Dioxide Production	3.7
Subpart FF—Underground Coal Mines	33.5
Subpart GG—Zinc Production	0.8
Subpart HH—Landfills	91.1
Subpart II—Wastewater	
Subpart JJ—Manure Management	1.5
Subpart OO—Suppliers of Industrial Greenhouse Gases	464.1
Subpart QQ—Motor Vehicle and Engine Manufacturers	35.4
Total	**3,869.9**[a]

[a]This estimate only includes downstream emissions. Adding upstream fuel suppliers emissions would increase this estimate by 30% but would double-count an unknown fraction of downstream emissions. While the fraction of overlap is unknown, it is estimated in Section 5.1.7.

Although the majority of cost and emissions information reported in this economic and small entity analysis is organized by subpart, EPA mapped each subpart to an industry included in the North American Industry Classification System (NAICS) so that they could be used in conjunction with economic census data. Since several subparts contain NAICS codes that fall into different sectors, they may appear in multiple sectors. For example, Subpart PP (suppliers of carbon dioxide (CO_2) include facilities with NAICS that fall into oil and natural gas transportation (NAICS 486), chemical manufacturing (NAICS 325), and oil and gas extraction (NAICS 211).

As shown in Table 5-2, the total national costs for the recommended option are estimated to be $168 million in the first year and $134 million in subsequent years ($2006). More than 90% of these costs fall on the private sector. Sectors bearing the greatest share of the ongoing costs of the rule are oil and natural gas systems (21%), general station combustion (18%), and iron and steel production (11%).

Table 5-2. National Cost Estimates by Sector: Recommended Option

		First Year			Subsequent Years		
Subpart	**NAICS**	**Million $2006**	**$/ton**	**Share**	**Million $2006**	**$/ton**	**Share**
Subpart A—General Provisions							
Subpart B—Electricity Use							
Subpart C—General Stationary Fuel Combustion Sources		$29.0	$0.13	17%	$24.4	$0.11	18%
Subpart D—Electricity Generation		$3.3	$0.00	2%	$3.3	$0.00	2%
Subpart E—Adipic Acid Production	325	$0.1	$0.01	0%	$0.1	$0.01	0%
Subpart F—Aluminum Production	331	$0.4	$0.07	0%	$0.4	$0.07	0%
Subpart G—Ammonia Manufacturing	325	$0.4	$0.03	0%	$0.3	$0.02	0%
Subpart H—Cement Production	327	$6.9	$0.08	4%	$4.3	$0.05	3%
Subpart I—Electronics Manufacturing	334, 335	$3.6	$0.63	2%	$3.6	$0.63	3%
Subpart J—Ethanol Production	325	$0.5		0%	$0.5		0%
Subpart K—Ferroalloy Production	331	$0.3	$0.11	0%	$0.2	$0.10	0%
Subpart L—Fluorinated Gas Production	325	$0.0	$0.01	0%	$0.0	$0.01	0%
Subpart M—Food Processing	311	$0.6		0%	$0.4		0%
Subpart N—Glass Production	327	$0.6	$0.26	0%	$0.4	$0.19	0%
Subpart O—HCFC-22 Production	325	$0.0	$0.00	0%	$0.0	$0.00	0%
Subpart P—Hydrogen Production	325	$0.6	$0.04	0%	$0.4	$0.03	0%
Subpart Q—Iron and Steel Production	331	$18.2	$0.21	11%	$14.1	$0.17	11%
Subpart R—Lead Production	331	$0.3	$0.37	0%	$0.3	$0.31	0%

(continued)

Table 5-2. National Cost Estimates by Sector: Recommended Option (continued)

		First Year			Subsequent Years		
Subpart	NAICS	Million $2006	$/ton	Share	Million $2006	$/ton	Share
Subpart S—Lime Manufacturing	327	$5.3	$0.21	3%	$3.0	$0.12	2%
Subpart T—Magnesium Production	331	$0.1	$0.04	0%	$0.1	$0.04	0%
Subpart U—Miscellaneous Uses of Carbonates		$0.0	$0.00	0%	$0.0	$0.00	0%
Subpart V—Nitric Acid Production	325	$0.9	$0.05	1%	$0.7	$0.04	1%
Subpart W—Oil and Natural Gas Systems	211, 486	$32.5	$0.25	19%	$28.1	$0.22	21%
Subpart X—Petrochemical Production	325	$1.6	$0.03	1%	$1.3	$0.02	1%
Subpart Y—Petroleum Refineries	324	$3.7	$0.02	2%	$2.8	$0.01	2%
Subpart Z—Phosphoric Acid Production	325	$0.8	$0.22	0%	$0.5	$0.12	0%
Subpart AA—Pulp and Paper Manufacturing	322	$9.2	$0.16	5%	$9.0	$0.16	7%
Subpart BB—Silicon Carbide Production	327	$0.0	$0.10	0%	$0.0	$0.09	0%
Subpart CC—Soda Ash Manufacturing	325	$0.0	$0.01	0%	$0.0	$0.01	0%
Subpart DD—Sulfur Hexafluoride (SF_6) from Electric Power Systems	221	$0.4	$0.04	0%	$0.4	$0.04	0%
Subpart EE—Titanium Dioxide Production	325	$0.1	$0.02	0%	$0.1	$0.02	0%
Subpart FF—Underground Coal Mines	212	$2.3	$0.07	1%	$2.3	$0.07	2%
Subpart GG—Zinc Production	331	$0.1	$0.12	0%	$0.1	$0.09	0%
Subpart HH—Landfills	562	$15.3	$0.17	9%	$10.4	$0.11	8%
Subpart II—Wastewater		$0.0	$0.00	0%	$0.0	$0.00	0%
Subpart JJ—Manure Management	112	$0.2	$0.14	0%	$0.2	$0.12	0%
Subpart LL—Suppliers of Coal-based Liquid Fuels	212	$11.0	$0.01	7%	$5.4	$0.00	4%
Subpart MM—Suppliers of Petroleum Products	324	$2.0	$0.00	1%	$0.8	$0.00	1%
Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids	221, 486	$2.1	$0.00	1%	$1.3	$0.00	1%
Subpart OO—Suppliers of Industrial Greenhouse Gases	325	$0.4	$0.00	0%	$0.4	$0.00	0%
Subpart PP—Suppliers of Carbon Dioxide (CO^2)	211, 325, 486	$0.0	$0.00	0%	$0.0	$0.00	0%
Subpart QQ—Motor Vehicle and Engine Manufacturers		$7.4	$0.21	4%	$7.4	$0.21	6%
Private Sector, Total		$160.4	$0.04	95%	$127.0	$0.03	95%
Public Sector, Total		$8.0		5%	$7.0		5%
Total		$168.4	$0.04	100%	$134.0	$0.03	100%

Note: An additional $3.5 million is incurred annually by the public sector during the rulemaking process, which will last between 1 and 2 years.

In addition to total national costs by sector under the recommended option, we also report average cost per ton to support additional analysis of the mandatory reporting programs. The average ongoing private cost per metric ton of CO_2e reported is $0.03. This measure varies by sector; measures range from less than $0.01 per ton (e.g., electricity generation [ARP]) to $0.63 per ton (electronics manufacturing).

5.1 Evaluating Alternative Options for Implementation of the Rule

The recommended option was evaluated based on a cost-effectiveness analysis. This approach compares the benefits and costs of alternative options for the rule. For example, in selecting the emissions threshold, we compared the incremental emissions reported with the incremental costs (associated with the change in the facilities that would be required to report their emissions). Similarly, in selecting the reporting methodology option, we compared the change in uncertainty with the change in costs associated with different emission measurement/estimation techniques. The metrics used and the results of the cost-effectiveness analysis are discussed below. A discussion of the number of reporters, methods, and cost assumptions associated with the alternative options is presented in the cost appendix (Appendix A) and in the Technical Support Documents (TSDs).

Ten alternative options were evaluated for this analysis. While we believe these 10 alternatives represent the most likely variations in the selected option, we recognize that in some cases particular interests may wish to evaluate more nuanced alternative options. To maintain transparency in the analysis, all of the data necessary to conduct further alternative option analyses can be found in Tables 4-81 and 4-82, specific industrial subsections in Section 4 of this document and in the cost appendix to the RIA. For example, if you wanted to change the coverage of fuel suppliers or the downstream coverage of specific fuels, such as natural gas or coal, you would evaluate the appropriate subparts for these fuels and using the data in cost appendix to the RIA or in Tables 4-81 – 4-82

5.1.1 Analysis of Alternative Threshold Options

The threshold, in large part, determines the number of entities required to report GHG emissions under the rule. The higher the threshold, the more entities that are excluded. It is assumed that the per unit/entity cost does not change at different thresholds so that changes in the national cost estimates are driven by the number of reporting entities. The per unit/entity costs outlined in Section 4, along with the estimates of numbers of covered entities at various thresholds, form the basis for this analysis. Two metrics are used to evaluate the cost-effectiveness of the emissions threshold. The first is the average cost per ton of emissions reported. The second metric for evaluating the threshold option is the marginal cost of reported emissions ($/ton CO_2E). To compute this metric, we compute the change in emissions reported by lowering or raising the threshold and divide this by the change in total reporting costs. Table 5-3 provides the cost-effectiveness analysis for the various thresholds. Throughout the alternative threshold option analysis, the analysis will typically report and compare differences in private costs because public costs do not vary with the alternative. The one exception is option 9, and in this case changes in private and public costs are reported. As shown in Table 5-3, the total average cost per ton for the recommended hybrid option of 25,000 tons CO_2e is approximately $0.04 (first year). As the threshold increases, the number of covered entities decreases, as does the total cost and the emissions covered, although not at the same rate. As a result, the total average cost per ton decreases from $0.04 to $0.03.

Table 5-3. Summary of Threshold Cost-Effectiveness Analysis (First Year): Recommended Hybrid Option is 25,000 tons CO_2e

Threshold (tons CO_2e)	Facilities Required to Report	Total Private Costs (million $2006)	$MtCO_2e$/ year Reported	Percentage of Total Emissions Reported	Average Reporting Cost ($2006/ton)	Marginal Cost ($2006/ton)
1,000	59,587	$426	3,951	56%	$0.11	$3.29
10,000	20,765	$213	3,916	56%	$0.05	$1.16
25,000	13,205	$160	3,870	55%	$0.04	
100,000	6,598	$101	3,699	52%	$0.03	−$0.35

The analysis also shows that the marginal cost (reduction) of moving from the recommended threshold of 25,000 tons CO_2e to a higher threshold (100,000 tons) is $0.35 per ton and decreases the total emissions captured by approximately 3%. Similarly, the marginal cost of moving the threshold from 25,000 to 10,000 is $1.16 per ton and increases the emissions captured by 1%. Finally, the marginal cost of lowering the threshold from 10,000 to 1,000 yields the highest cost increase in marginal cost reported ($3.29 per ton), and increases the percentage of covered emissions by less than 1%. Similar data is presented for subsequent year in Table 5-4. Information on how costs are distributed across sectors at each threshold are provided in the following tables: Table 5-5 (1,000 tCO_2e threshold), Table 5-6 (10,000 tCO_2e threshold), Table 5-2 (25,000 tCO_2e threshold), and Table 5-7 (100,000 tCO_2e threshold).

Table 5-4. Summary of Threshold Cost-Effectiveness Analysis (Subsequent Years)

Threshold (tons CO_2e)	Entities (covered)	Total Private Costs (millions $2006)	MT CO_2e/year (covered)	Percentage of Total Emissions Reported	Total Average Cost ($2006/ton)	Marginal Cost ($2006/ton)
1,000	59,587	$372	3,951	56%	$0.09	$2.62
10,000	20,765	$174	3,916	56%	$0.04	$0.30
25,000	13,205	$127	3,870	55%	$0.03	
100,000	6,598	$79	3,699	52%	$0.02	−$0.48

Table 5-5. National Cost Estimates by Sector: 1,000 tCO_2e Threshold

Sector	First Year $	First Year $/ton	First Year Share	Subsequent Years $	Subsequent Years $/ton	Subsequent Years Share
Subpart A—General Provisions						
Subpart B—Electricity Use						
Subpart C—General Stationary Fuel Combustion Sources	$189.7	$0.76	44%	$184.9	$0.74	49%
Subpart D—Electricity Generation	$3.3	$0.00	1%	$3.3	$0.00	1%
Subpart E—Adipic Acid Production	$0.1	$0.01	0%	$0.1	$0.01	0%
Subpart F—Aluminum Production	$0.4	$0.07	0%	$0.4	$0.07	0%
Subpart G—Ammonia Manufacturing	$0.4	$0.03	0%	$0.3	$0.02	0%
Subpart H—Cement Production	$6.9	$0.08	2%	$4.3	$0.05	1%
Subpart I—Electronics Manufacturing	$4.8	$0.80	1%	$4.8	$0.80	1%
Subpart J—Ethanol Production	$0.5		0%	$0.5		0%
Subpart K—Ferroalloy Production	$0.3	$0.11	0%	$0.2	$0.10	0%
Subpart L—Fluorinated Gas Production	$0.0	$0.01	0%	$0.0	$0.01	0%
Subpart M—Food Processing	$4.0		1%	$3.6		1%
Subpart N—Glass Production	$2.3	$0.53	1%	$1.7	$0.38	0%
Subpart O—HCFC-22 Production	$0.0	$0.00	0%	$0.0	$0.00	0%
Subpart P—Hydrogen Production	$0.9	$0.06	0%	$0.7	$0.04	0%
Subpart Q—Iron and Steel Production	$19.6	$0.23	5%	$15.2	$0.18	4%
Subpart R—Lead Production	$0.4	$0.45	0%	$0.3	$0.38	0%
Subpart S—Lime Manufacturing	$5.3	$0.21	1%	$3.0	$0.12	1%
Subpart T—Magnesium Production	$0.1	$0.04	0%	$0.1	$0.04	0%
Subpart U—Miscellaneous Uses of Carbonates	$0.0	$0.00	0%	$0.0	$0.00	0%
Subpart V—Nitric Acid Production	$0.9	$0.05	0%	$0.7	$0.04	0%
Subpart W—Oil and Natural Gas Systems	$63.1	$0.42	15%	$52.6	$0.35	14%
Subpart X—Petrochemical Production	$1.6	$0.03	0%	$1.3	$0.02	0%
Subpart Y—Petroleum Refineries	$3.7	$0.02	1%	$2.8	$0.01	1%
Subpart Z—Phosphoric Acid Production	$0.8	$0.22	0%	$0.5	$0.12	0%
Subpart AA—Pulp and Paper Manufacturing	$9.4	$0.16	2%	$9.0	$0.16	2%
Subpart BB—Silicon Carbide Production	$0.0	$0.10	0%	$0.0	$0.09	0%
Subpart CC—Soda Ash Manufacturing	$0.0	$0.01	0%	$0.0	$0.01	0%
Subpart DD—Sulfur Hexafluoride (SF_6) from Electric Power Systems	$1.6	$0.13	0%	$1.6	$0.13	0%
Subpart EE—Titanium Dioxide Production	$0.1	$0.02	0%	$0.1	$0.02	0%
Subpart FF—Underground Coal Mines	$2.9	$0.08	1%	$2.9	$0.08	1%
Subpart GG—Zinc Production	$0.1	$0.15	0%	$0.1	$0.12	0%
Subpart HH—Landfills	$35.8	$0.32	8%	$22.6	$0.20	6%
Subpart II—Wastewater	$0.0	$0.00	0%	$0.0	$0.00	0%

(continued)

Table 5-5. National Cost Estimates by Sector: 1,000 tCO_2e Threshold (continued)

Sector	First Year			Subsequent Years		
	$	$/ton	Share	$	$/ton	Share
Subpart JJ—Manure Management	$42.5	$5.30	10%	$38.0	$4.73	10%
Subpart KK—Suppliers of Coal and Coal-based Products and Subpart LL—Suppliers of Coal-based Liquid Fuels	$11.3	$0.01	3%	$5.5	$0.00	1%
Subpart MM—Suppliers of Petroleum Products	$3.1	$0.00	1%	$1.2	$0.00	0%
Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids	$2.4	$0.00	1%	$1.5	$0.00	0%
Subpart OO—Suppliers of Industrial Greenhouse Gases	$0.4	$0.00	0%	$0.4	$0.00	0%
Subpart PP—Suppliers of Carbon Dioxide (CO_2)	$0.0	$0.00	0%	$0.0	$0.00	0%
Subpart QQ—Motor Vehicle and Engine Manufacturers	$7.4	$0.21	2%	$7.4	$0.21	2%
Private Sector, Total	$426.3	$0.1	98%	$371.6	$0.1	98%
Public Sector, Total	$8.0		2%	$7.0		2%
Total	$434.3	$0.1	100%	$378.6	$0.1	100%

Table 5-6. National Cost Estimates by Sector: 10,000 tCO_2e Threshold

Sector	First Year			Subsequent Years		
	$	$/ton	Share	$	$/ton	Share
Subpart A—General Provisions						
Subpart B—Electricity Use						
Subpart C—General Stationary Fuel Combustion Sources	$56.9	$0.25	26%	$52.2	$0.23	29%
Subpart D—Electricity Generation	$3.3	$0.00	1%	$3.3	$0.00	2%
Subpart E—Adipic Acid Production	$0.1	$0.01	0%	$0.1	$0.01	0%
Subpart F—Aluminum Production	$0.4	$0.07	0%	$0.4	$0.07	0%
Subpart G—Ammonia Manufacturing	$0.4	$0.03	0%	$0.3	$0.02	0%
Subpart H—Cement Production	$6.9	$0.08	3%	$4.3	$0.05	2%
Subpart I—Electronics Manufacturing	$4.0	$0.69	2%	$4.0	$0.69	2%
Subpart J—Ethanol Production	$0.4		0%	$0.4		0%
Subpart K—Ferroalloy Production	$0.3	$0.11	0%	$0.2	$0.10	0%
Subpart L—Fluorinated Gas Production	$0.0	$0.01	0%	$0.0	$0.01	0%
Subpart M—Food Processing	$1.2		1%	$0.9		0%
Subpart N—Glass Production	$1.7	$0.41	1%	$1.2	$0.30	1%
Subpart O—HCFC-22 Production	$0.0	$0.00	0%	$0.0	$0.00	0%
Subpart P—Hydrogen Production	$0.8	$0.05	0%	$0.6	$0.04	0%

(continued)

Table 5-6. National Cost Estimates by Sector: 10,000 tCO_2e Threshold (continued)

Sector	First Year			Subsequent Years		
	$	$/ton	Share	$	$/ton	Share
Subpart Q—Iron and Steel Production	$19.3	$0.23	9%	$15.0	$0.18	8%
Subpart R—Lead Production	$0.4	$0.42	0%	$0.3	$0.36	0%
Subpart S—Lime Manufacturing	$5.3	$0.21	2%	$3.0	$0.12	2%
Subpart T—Magnesium Production	$0.1	$0.04	0%	$0.1	$0.04	0%
Subpart U—Miscellaneous Uses of Carbonates	$0.0	$0.00	0%	$0.0	$0.00	0%
Subpart V—Nitric Acid Production	$0.9	$0.05	0%	$0.7	$0.04	0%
Subpart W—Oil and Natural Gas Systems	$45.9	$0.32	21%	$39.1	$0.28	22%
Subpart X—Petrochemical Production	$1.6	$0.03	1%	$1.3	$0.02	1%
Subpart Y—Petroleum Refineries	$3.7	$0.02	2%	$2.8	$0.01	2%
Subpart Z—Phosphoric Acid Production	$0.8	$0.22	0%	$0.5	$0.12	0%
Subpart AA—Pulp and Paper Manufacturing	$9.4	$0.16	4%	$9.0	$0.16	5%
Subpart BB—Silicon Carbide Production	$0.0	$0.10	0%	$0.0	$0.09	0%
Subpart CC—Soda Ash Manufacturing	$0.0	$0.01	0%	$0.0	$0.01	0%
Subpart DD—Sulfur Hexafluoride (SF_6) from Electric Power Systems	$0.5	$0.05	0%	$0.5	$0.05	0%
Subpart EE—Titanium Dioxide Production	$0.1	$0.02	0%	$0.1	$0.02	0%
Subpart FF—Underground Coal Mines	$2.8	$0.08	1%	$2.8	$0.08	2%
Subpart GG—Zinc Production	$0.1	$0.15	0%	$0.1	$0.11	0%
Subpart HH—Landfills	$19.8	$0.19	9%	$13.1	$0.13	7%
Subpart II—Wastewater	$0.0	$0.00	0%	$0.0	$0.00	0%
Subpart JJ—Manure Management	$2.1	$0.26	1%	$1.9	$0.23	1%
Subpart KK—Suppliers of Coal and Coal-based Products and Subpart LL—Suppliers of Coal-based Liquid Fuels	$11.0	$0.01	5%	$5.4	$0.00	3%
Subpart MM—Suppliers of Petroleum Products	$2.9	$0.00	1%	$1.1	$0.00	1%
Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids	$2.2	$0.00	1%	$1.4	$0.00	1%
Subpart OO—Suppliers of Industrial Greenhouse Gases	$0.4	$0.00	0%	$0.4	$0.00	0%
Subpart PP—Suppliers of Carbon Dioxide (CO_2)	$0.0	$0.00	0%	$0.0	$0.00	0%
Subpart QQ—Motor Vehicle and Engine Manufacturers	$7.4	$0.21	3%	$7.4	$0.21	4%
Private Sector, Total	$213.3	$0.05	96%	$174.0	$0.04	96%
Public Sector, Total	$8.0		4%	$7.0		4%
Total	$221.3	$0.06	100%	$181.0	$0.05	100%

Table 5-7. National Cost Estimates by Sector: 100,000 tCO_2e Threshold

	First Year			Subsequent Years		
Sector	**$**	**$/ton**	**Share**	**$**	**$/ton**	**Share**
Subpart A—General Provisions						
Subpart B—Electricity Use						
Subpart C—General Stationary Fuel Combustion Sources	$10.4	$0.06	9%	$7.5	$0.04	9%
Subpart D—Electricity Generation	$3.3	$0.00	3%	$3.3	$0.00	4%
Subpart E—Adipic Acid Production	$0.1	$0.01	0%	$0.1	$0.01	0%
Subpart F—Aluminum Production	$0.4	$0.07	0%	$0.4	$0.07	0%
Subpart G—Ammonia Manufacturing	$0.4	$0.03	0%	$0.3	$0.02	0%
Subpart H—Cement Production	$6.9	$0.08	6%	$4.3	$0.05	5%
Subpart I—Electronics Manufacturing	$2.8	$0.59	3%	$2.8	$0.59	3%
Subpart J—Ethanol Production	$0.2		0%	$0.2		0%
Subpart K—Ferroalloy Production	$0.2	$0.10	0%	$0.2	$0.09	0%
Subpart L—Fluorinated Gas Production	$0.0	$0.00	0%	$0.0	$0.00	0%
Subpart M—Food Processing	$0.1		0%	$0.0		0%
Subpart N—Glass Production	$0.0	$0.05	0%	$0.0	$0.04	0%
Subpart O—HCFC-22 Production	$0.0	$0.00	0%	$0.0	$0.00	0%
Subpart P—Hydrogen Production	$0.4	$0.03	0%	$0.3	$0.02	0%
Subpart Q—Iron and Steel Production	$16.7	$0.20	15%	$13.0	$0.15	15%
Subpart R—Lead Production	$0.00	$0.00	0%	$0.0	$0.00	0%
Subpart S—Lime Manufacturing	$5.2	$0.22	5%	$2.9	$0.12	3%
Subpart T—Magnesium Production	$0.1	$0.04	0%	$0.1	$0.04	0%
Subpart U—Miscellaneous Uses of Carbonates	$0.0	$0.00	0%	$0.0	$0.00	0%
Subpart V—Nitric Acid Production	$0.8	$0.05	1%	$0.7	$0.04	1%
Subpart W—Oil and Natural Gas Systems	$10.7	$0.13	10%	$9.7	$0.12	11%
Subpart X—Petrochemical Production	$1.6	$0.03	1%	$1.2	$0.02	1%
Subpart Y—Petroleum Refineries	$3.1	$0.02	3%	$2.4	$0.01	3%
Subpart Z—Phosphoric Acid Production	$0.8	$0.22	1%	$0.5	$0.12	1%
Subpart AA—Pulp and Paper Manufacturing	$8.6	$0.15	8%	$8.5	$0.15	10%
Subpart BB—Silicon Carbide Production	$0.0	$0.10	0%	$0.0	$0.09	0%
Subpart CC—Soda Ash Manufacturing	$0.0	$0.01	0%	$0.0	$0.01	0%
Subpart DD—Sulfur Hexafluoride (SF_6) from Electric Power Systems	$0.1	$0.02	0%	$0.1	$0.02	0%
Subpart EE—Titanium Dioxide Production	$0.1	$0.02	0%	$0.1	$0.02	0%
Subpart FF—Underground Coal Mines	$1.3	$0.04	1%	$1.3	$0.04	2%
Subpart GG—Zinc Production	$0.1	$0.09	0%	$0.1	$0.07	0%
Subpart HH—Landfills	$6.7	$0.10	6%	$4.7	$0.07	6%
Subpart II—Wastewater	$0.0	$0.00	0%	$0.0	$0.00	0%

(continued)

Table 5-7. National Cost Estimates by Sector: 100,000 tCO_2e Threshold (continued)

Sector	First Year			Subsequent Years		
	$	$/ton	Share	$	$/ton	Share
Subpart JJ—Manure Management	$0.0	$0.00	0%	$0.0	$0.00	0%
Subpart KK—Suppliers of Coal and Coal-based Products and Subpart LL—Suppliers of Coal-based Liquid Fuels	$10.0	$0.00	9%	$5.0	$0.00	6%
Subpart MM—Suppliers of Petroleum Products	$2.0	$0.00	2%	$0.8	$0.00	1%
Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids	$0.7	$0.00	1%	$0.5	$0.00	1%
Subpart OO—Suppliers of Industrial Greenhouse Gases	$0.2	$0.00	0%	$0.2	$0.00	0%
Subpart PP—Suppliers of Carbon Dioxide (CO_2)	$0.0	$0.00	0%	$0.0	$0.00	0%
Subpart QQ—Motor Vehicle and Engine Manufacturers	$7.4	$0.21	7%	$7.4	$0.21	9%
Private Sector, Total	$101.5	$0.03	93%	$78.6	$0.02	92%
Public Sector, Total	$8.0		7%	$7.0		8%
Total	$109.5	$0.03	100%	$85.6	$0.02	100%

The selection decision weighed the marginal cost of capturing additional emissions with the percentage of emissions needed to accurately estimate the U.S. GHG emissions nationally and by sector. This is shown in Figure 5-1, which illustrates the total average cost per ton and the marginal cost per ton as a function of the percentage of total emissions reported.

In addition to the typical emissions thresholds associated with GHG reporting and reduction programs (e.g., 25,000 metric tons CO_2e), under the CAA, there are (1) the Title V program that requires all major stationary sources with emissions over 100 tons per year (tpy) to hold an operating permit and (2) the Prevention of Significant Deterioration (PSD)/New Source Review (NSR) program that requires new major sources and major sources that are undergoing major modifications to obtain a permit. A major source for NSR/PSD is defined as any source that emits or has the potential to emit either 100 tpy or 250 tpy of a regulated pollutant, dependent on the source category and attainment status of the area. The 100 tpy level is the level at which existing sources in 28 industry categories listed in the CAA are classified as major for the PSD program. The 250 tpy level is the level at which existing sources in all other categories are classified as major for PSD purposes.

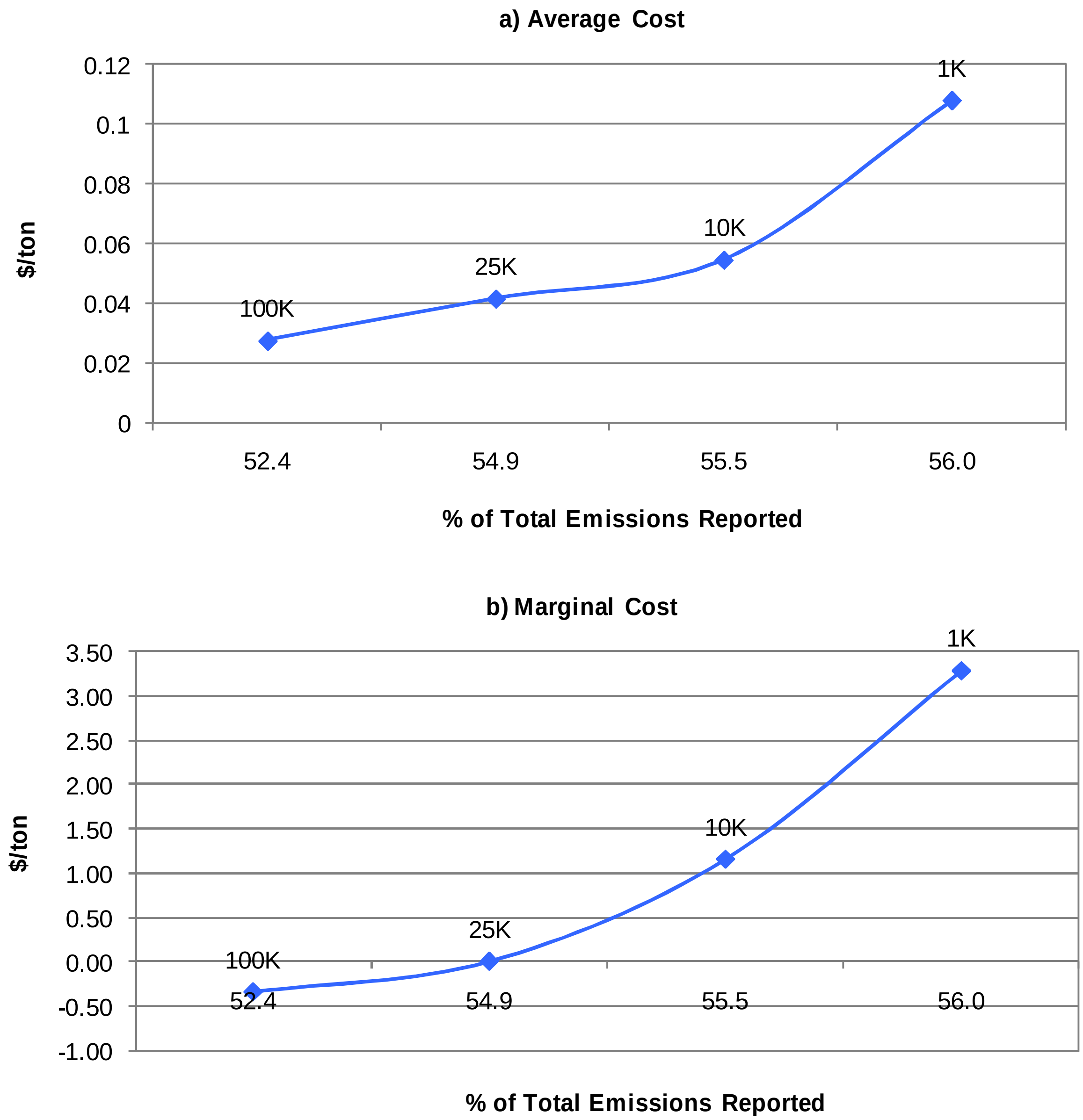

Figure 5-1. Average and Marginal Cost per Ton of Emissions Reported by Threshold

EPA performed some preliminary analyses to generally estimate the existing stock of major sources in order to then estimate the approximate number of new facilities that could be required to obtain NSR/PSD permits. EPA roughly estimated that currently approximately 350,000 facilities have emissions greater than 100 tons per year, while approximately 235,000 have more than 250 tons per year. If the 100 and 250 tpy thresholds were applied in the context of GHGs, the Agency estimates the number of PSD permits required to be issued each year would increase by a factor greater than 10 (i.e., more than 2,000 to 3,000 permits per year). The additional permits would generally be issued to smaller industrial sources, as well as large office and residential buildings, hotels, large retail establishments, and similar facilities. EPA rejected setting similar reporting thresholds in this proposal due to the uncertainty in the estimates in the number of affected facilities and the additional burden likely placed on a large number of small sources.

It should be noted that the estimates in the ANPR of sources that would be required to report are rough estimates and are not as robust as the threshold analysis performed for this proposed rule. In addition, even if we assumed the per facility costs were the same, a threshold significantly lower than the 25,000 ton hybrid threshold would dramatically increase the cost of the rule overall and more than likely impose significant small business impacts.

5.1.2 Analysis of Alternative Monitory Method Options

Each monitoring technique for which reporting costs were estimated in Section 4 is expected to provide the same level of emissions coverage. However, the different methods of monitoring emissions differ in their accuracy in estimating actual emissions. Therefore, the gain from increasing the cost of monitoring is to have more precise estimates of facility emissions. The methods considered for determining emissions ranged from applying average industry parameters (referred to as "default parameters") to material inputs or throughputs, to the use of CEMS to directly measure emissions. As discussed previously, the selected option (referred to as the "hybrid method") requires the use of CEMS if they are already required for other regulations; otherwise, facility-specific measurements are made to support calculations of GHG emissions. In this section, we evaluate the change in cost and change in accuracy for two alternative monitoring options. Generally speaking, under one of the alternatives, default parameters would be used in lieu of CEMS and facility-level estimates, and in the other options, CEMS are required for all sources. We use the term "CEMS" and "default parameters" as shorthand to describe alternative options. Estimated costs for each monitoring method are shown in Table 5-8.

To compute the cost for the CEMS option, we multiply the recommended option costs by a ratio of Tier 4 costs ($56,040 in the first year and $31, 325 in subsequent years) to Tier 2 costs ($5,500 in both first and subsequent years). This ratio is estimated to be 10.2 in the first year and 5.7 in subsequent years . The Tier 4 option applies to non-Part 75, non-EGU (industrial) units where O_2 analyzers will not suffice (e.g., sources with process emissions [cement, lime, glass]) and requires adding a CO_2 analyzer and flow meter (see discussion in Section 4). For the Tier 2 methodology, CO_2 mass emissions are estimated using measured high heat values, a default CO_2

emission factor, a default oxidation factor, and the quantity of fuel combusted. Default CH_4 and N_2O emission factors and measure heat content (see stationary combustion TSD).

For the default parameter options, we use a ratio of Tier 1 costs ($2,200 in both first and subsequent years) to Tier 2 costs ($5,500 in both first and subsequent years), or 0.40 in both first and subsequent years. The Tier 1 method includes calculation with fuel-specific default emission factors, a default high heating value, a default oxidation factor, and the annual fuel consumption. Measurement of annual fuel consumption is assumed to be a standard business practice and not included in incremental cost of the GHG monitoring (see stationary combustion TSD). First year costs include a monitoring plan and a QA/QC plan.

EPA contract engineers also developed uncertainty estimates for all three methods for each affected sector. The uncertainties in individual measurements were based on quoted accuracies of the instruments or engineering judgment. These individual measurement uncertainties were assumed to represent 95% confidence intervals. Uncertainties in the overall method were determined via error propagation or Monte Carlo assessment and reported as the 95% confidence interval about the mean or expected value (as a percentage of that value).

5.1.2.1 Monitoring Method Uncertainty

For 10 of the top GHG emitting sectors, engineering experts were asked to provide uncertainty values for the three methodologies being considered. This information is shown in Table 5-9. Whereas the CEMS approach is constant at 7%, the uncertainty for the engineering and hybrid methods varies considerably across sectors. The highest uncertainty was associated with using the engineering estimate method to estimate emissions in industrial gas manufacturing. For the industrial gas sector, applying the default parameter approach requires measuring production flows accurately and calculating the flow difference to estimate emissions. However, while the uncertainty in the production flow measurement can be as low as 0.5%, this yields a 50% uncertainty in the difference (emissions) if losses are on the order of 1% of production.

In general, the uncertainty cost-effectiveness analysis was useful in selecting the recommended hybrid methodology and was evaluated in conjunction with other considerations such as consistency with other regulations and the burden on small entities.

To evaluate the trade-off between cost and uncertainty across the alternative methods, three measures (i.e., metrics) of cost-effectiveness were developed.

1. Incremental cost. This is the total national private cost difference between the options. For example, as illustrated in Tables 5-10 and 5-11, by moving from the recommended hybrid method to CEMS, the total national cost increases by $1,474 million for the first year and $597 million for subsequent years.[11]
2. Average cost per percentage point uncertainty. This compares the average cost per percentage point uncertainty across the three alternative methods. For example, the cost for the recommended hybrid method is ($160M/9.4) = $17.1M per percentage point uncertainty. The average cost for the CEMS and default parameter approaches are ($1,634M/7.0) = 234M and ($64M/19.7) = 3.3M, respectively.
3. Marginal cost per percentage point reduction in uncertainty. This compares the cost of reducing the coefficient of variation by 1%. For example, the incremental cost per percent point in going from a default parameter approach to a hybrid approach is $96M/(19.7–9.4) = $9.3M, and the incremental cost of moving from a hybrid approach to an approach where CEMS are used is $M1,474/(9.4–7.0) = $614M.

[11]To compute the cost for the CEMS option, we multiply the recommended option costs by a ratio of Tier 4 costs ($33,804) to Tier 2 costs ($5,500), or 6.15. For the default parameter options, we use a ratio of Tier 1 costs ($2,200) to Tier 2 costs, or 0.40.

Table 5-8. Analysis of Alternative Monitoring Methods by Sector

Sector	CEMS		Recommended Option (Hybrid Approach)				Default Parameters	
	First Year (million $2006)	Subsequent Years (million $2006)	# of Units/Entities using CEMS	% of Units/Entities Using CEMS	First Year (million $2006)	Subsequent Years (million $2006)	First Year (million $2006)	Subsequent Years (million $2006)
Subpart A—General Provisions								
Subpart B—Electricity Use								
Subpart C—General Stationary Fuel Combustion Sources	$295.2	$138.9	1,491	17%	$29.0	$24.4	$11.6	$9.8
Subpart D—Electricity Generation	$33.7	$18.9	3,279	100%	$3.3	$3.3	$1.3	$1.3
Subpart E—Adipic Acid Production	$1.0	$0.4	4	100%	$0.1	$0.1	$0.0	$0.0
Subpart F—Aluminum Production	$4.5	$2.5			$0.4	$0.4	$0.2	$0.2
Subpart G—Ammonia Manufacturing	$4.6	$1.8	24	100%	$0.4	$0.3	$0.2	$0.1
Subpart H—Cement Production	$70.6	$24.3	107	100%	$6.9	$4.3	$2.8	$1.7
Subpart I—Electronics Manufacturing	$36.6	$20.5			$3.6	$3.6	$1.4	$1.4
Subpart J—Ethanol Production	$4.7	$2.6			$0.5	$0.5	$0.2	$0.2
Subpart K—Ferroalloy Production	$2.6	$1.3	6	100%	$0.3	$0.2	$0.1	$0.1
Subpart L—Fluorinated Gas Production	$0.3	$0.2			$0.0	$0.0	$0.0	$0.0
Subpart M—Food Processing	$6.0	$2.3			$0.6	$0.4	$0.2	$0.2
Subpart N—Glass Production	$5.9	$2.4	55	100%	$0.6	$0.4	$0.2	$0.2
Subpart O—HCFC-22 Production	$0.2	$0.1			$0.0	$0.0	$0.0	$0.0
Subpart P—Hydrogen Production	$5.8	$2.3	51	100%	$0.6	$0.4	$0.2	$0.2
Subpart Q—Iron and Steel Production	$185.4	$80.5	[a]	[a]	$18.2	$14.1	$7.3	$5.7
Subpart R—Lead Production	$3.0	$1.4	13	100%	$0.3	$0.3	$0.1	$0.1

(continued)

Table 5-8. Analysis of Alternative Monitoring Methods by Sector (continued)

Sector	CEMS		Recommended Option (Hybrid Approach)				Default Parameters	
	First Year (million $2006)	Subsequent Years (million $2006)	# of Units/Entities using CEMS	% of Units/Entities Using CEMS	First Year (million $2006)	Subsequent Years (million $2006)	First Year (million $2006)	Subsequent Years (million $2006)
Subpart S—Lime Manufacturing	$54.2	$17.2	89	100%	$5.3	$3.0	$2.1	$1.2
Subpart T—Magnesium Production	$1.2	$0.7			$0.1	$0.1	$0.0	$0.0
Subpart U—Miscellaneous Uses of Carbonates	$0.0	$0.0			$0.0	$0.0	$0.0	$0.0
Subpart V—Nitric Acid Production	$9.1	$4.2	4	100%	$0.9	$0.7	$0.4	$0.3
Subpart W—Oil and Natural Gas Systems	$331.2	$160.2			$32.5	$28.1	$13.0	$11.2
Subpart X—Petrochemical Production	$16.8	$7.4	[a]	[a]	$1.6	$1.3	$0.7	$0.5
Subpart Y—Petroleum Refineries	$37.2	$15.9	[a]	[a]	$3.7	$2.8	$1.5	$1.1
Subpart Z—Phosphoric Acid Production	$8.5	$2.7	14	100%	$0.8	$0.5	$0.3	$0.2
Subpart AA—Pulp and Paper Manufacturing	$93.3	$51.0	[a]	[a]	$9.2	$9.0	$3.7	$3.6
Subpart BB—Silicon Carbide Production	$0.1	$0.1			$0.0	$0.0	$0.0	$0.0
Subpart CC—Soda Ash Manufacturing	$0.5	$0.2			$0.0	$0.0	$0.0	$0.0
Subpart DD—Sulfur Hexafluoride (SF_6) from Electric Power Systems	$3.9	$2.2			$0.4	$0.4	$0.2	$0.2
Subpart EE—Titanium Dioxide Production	$0.8	$0.4			$0.1	$0.1	$0.0	$0.0
Subpart FF—Underground Coal Mines	$23.9	$13.2			$2.3	$2.3	$0.9	$0.9

(continued)

Table 5-8. Analysis of Alternative Monitoring Methods by Sector (continued)

Sector	CEMS		Recommended Option (Hybrid Approach)				Default Parameters	
	First Year (million $2006)	Subsequent Years (million $2006)	# of Units/Entities using CEMS	% of Units/Entities Using CEMS	First Year (million $2006)	Subsequent Years (million $2006)	First Year (million $2006)	Subsequent Years (million $2006)
Subpart GG—Zinc Production	$0.9	$0.4	8	100%	$0.1	$0.1	$0.0	$0.0
Subpart HH—Landfills	$156.3	$59.2			$15.3	$10.4	$6.1	$4.2
Subpart II—Wastewater	$0.0	$0.0			$0.0	$0.0	$0.0	$0.0
Subpart JJ—Manure Management	$2.1	$1.0			$0.2	$0.2	$0.1	$0.1
Subpart KK—Suppliers of Coal and Coal-based Products and Subpart LL—Suppliers of Coal-based Liquid Fuels	$112.4	$30.8			$11.0	$5.4	$4.4	$2.2
Subpart MM—Suppliers of Petroleum Products	$20.3	$4.3			$2.0	$0.8	$0.8	$0.3
Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids	$21.8	$7.5			$2.1	$1.3	$0.9	$0.5
Subpart OO—Suppliers of Industrial Greenhouse Gases	$3.9	$2.2			$0.4	$0.4	$0.2	$0.2
Subpart PP—Suppliers of Carbon Dioxide (CO2)	$0.3	$0.2			$0.0	$0.0	$0.0	$0.0
Subpart QQ—Motor Vehicle and Engine Manufacturers	$75.5	$42.2			$7.4	$7.4	$3.0	$3.0
Private Sector, Total	$1,634.0	$724.0			$160.4	$127.0	$64.2	$50.8
Public Sector, Total	$8.0	$7.0			$8.0	$7.0	$8.0	$7.0
Total	$1,642.4	$730.6			$168.4	$134.0	$72.2	$57.8

[a] Subparts Q X, Y, and AA also use of CEMS to directly measure emissions as part of the hybrid approach. However, due to a lack of information counts for the units of CEMS used in each subpart is not available.

Table 5-9. Uncertainty Estimates by Methodology Option

	Share of Total Emission	Uncertainty Estimates		
		Engr. Est	Hybrid	CEMS
Electricity generation (ARP, non-ARP, and MSW)	57%	10%	8%	7%
Industrial gas manufacturing				
Fluorocarbon producers	13%	50%	10%	7%
Imports/exports of industrial gases-SF7	3%	50%	10%	7%
Electricity generation (ARP, non-ARP, and MSW)	57%	10%	8%	7%
Industrial				
Petroleum refineries	7%	18%	7%	7%
Pulp, paper, and paperboard mills	3%	22%	10%	7%
Iron and steel mills	2%	15%	25%	7%
Cement manufacturing	1%	17%	9%	7%
Oil gas and mining				
Gas processing	1%	50%	30%	7%
Compressor stations	2%	50%	30%	7%
Weighted Average		**19.7%**	**9.4%**	**7.0%**

Note: Uncertainty estimates for the three options are presented as point estimates. Uncertainty ranges were not available for all sectors.

Table 5-10. Uncertainty Cost-Effectiveness Analysis (First Year): Recommended Option is the Hybrid Approach

Threshold = 25,000	First Year Total Private Costs (million $2006)	$MtCO_2e$/ Year (covered)	Average Uncertainty	Incremental Cost (million $2006)	Average Cost per Percentage Point of Uncertainty (million $2006/%)	Marginal Cost per Percentage Point Uncertainty (million 2006/%)
CEMS	$1,634	3,870	7.00%	$1,474	$233.5	$614.2
Recommended—hybrid	$160	3,870	9.40%		$17.1	
Default parameters	$64	3,870	19.70%	$96	$3.3	$9.3

Table 5-11. Uncertainty Cost-Effectiveness Analysis (Subsequent Year): Recommended Option is the Hybrid Approach

Threshold = 25,000	Total Private Costs (million $2006)	$MtCO_2e$/ Year (covered)	Average Uncertainty	Incremental Cost (million $2006)	Average Cost per % Point of Uncertainty	Marginal Cost per % Point of Uncertainty
CEMS	$724	3,870	7.00%	$597	$103.4	$248.6
Recommended—hybrid	$127	3,870	9.40%		$13.5	
Default parameters	$51	3,870	19.70%	$76	$2.6	$7.4

Figure 5-2 shows the average cost per percentage point of uncertainty. The figure shows that the average cost increases rapidly as uncertainty decreases.

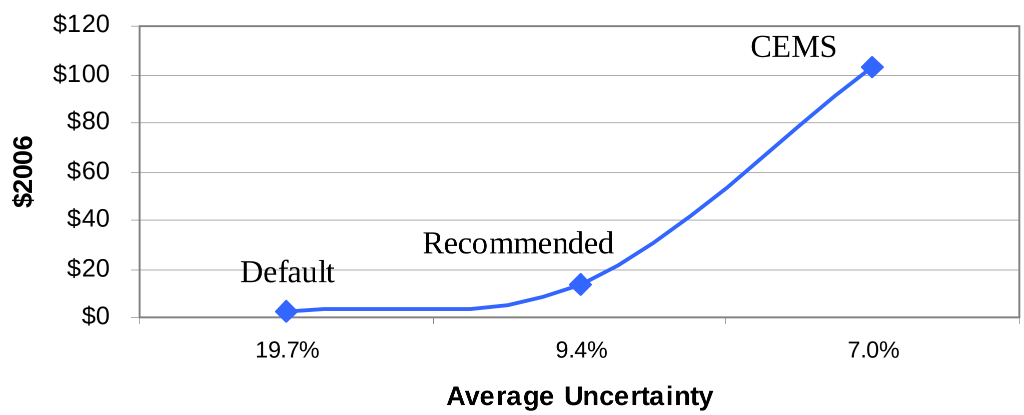

Figure 5-2. Average Cost per Percentage Point of Uncertainty

5.1.3 EPA Uses Existing Federal Data for Fuel Quantity (Option 2a)

Under this scenario, upstream fuel suppliers (Subparts KK, MM, NN), would not be required to report their fuel quantity data to EPA. Rather than collecting this information from upstream fuel suppliers, the EPA would access the quantity data each fuel supplier is currently reporting to other federal agencies such as EIA. The reduction in cost from this option is a result of fuel suppliers not having to duplicate the reporting of their fuel quantity data. However, most other costs will stay the same because suppliers currently do not test for carbon content and because they will still have to report fuel quality (i.e., carbon content) directly to EPA. It is assumed that the accuracy and coverage of reported emissions for fuel suppliers would be unchanged under this scenario.

Table 5-12. Alternative Option 6

	Number of Reporters (covered)	$MtCO_2e$/ Year (covered)	First Year Private Costs (million $2006)	Subsequent Year Private Costs (million $2006)
Recommended option	13,205	3,870	$160.4	$127.0
Alternative options				
6. Existing federal data used for measurement of fuel suppliers; recommended option for threshold, frequency, verifier, and methodology for other sources.	13,205	3,870	$160.1	$126.7
Absolute difference	0	0	−0.3	−0.3
Percentage difference	0%	0%	−0.2%	−0.3%

EPA estimates that this would result in a labor savings of 2 hours for each reporting entity, yielding a decreased private sector cost of $0.3 million.

$$(3{,}005 \text{ entities}) \times (2 \text{ hrs/entity}) \times (57 \text{ \$/hr}) = \$342{,}570$$

However, there likely would be an increased cost to the public sector resulting from the EPA need to obtain data from EIA and integrate the data with the fuel quality information obtained from the GHG mandatory reporting rule. In addition, this task will be complicated by issues related to maintaining data confidentiality, as discussed in the preamble. As a result, it is unclear whether this option will result in a net decrease in total national costs of the program.

5.1.4 EPA Uses Default Carbon Content for Fuel Suppliers (Option 2b)

Under this scenario, the only change to the recommended approach is that fuel suppliers (Subparts KK, MM, NN), are only required to report their downstream emissions. EPA would use default carbon content parameters for its analysis. Under this scenario, the fuel suppliers' first year costs would decrease from $15.2 million to zero. However, this change would increase the uncertainty of the emissions estimate from 4% to 6% (see Section 6 for a discussion of uncertainty estimates).

Table 5-13. Alternative Option 7

	Number of Reporters (covered)	$MtCO_2e$/ Year (covered)	First Year Private Costs (million $2006)	Subsequent Year Private Costs (million $2006)
Recommended option	13,205	3,870	$160.4	$127.0
Alternative options				
7. EPA uses default carbon content for fuel suppliers; recommended option for threshold, frequency, verifier, and methodology for other sources.	13,205	3,870	$145.2	$119.6
Absolute difference	0	0	−15.2	−7.5
Percentage difference	0%	0%	−9.5%	−5.9%

The 2% change in uncertainty represents 51.3 $MtCO_2e$ (2,567 $MtCO_2e \times 0.02$) of emissions uncertainty for fuel suppliers. This yields a marginal cost of uncertainty of

$$\$15.2 \text{ million} / 51.3\ MtCO_2e = 0.30\$/tCO_2e$$

5.1.5 Frequency of Reporting: Quarterly

The recommended reporting frequency is annually, unless entities are already required to report quarterly. Under this scenario, all entities are required to report quarterly. To compute the cost of the rule under a quarterly reporting scenario, we assume these costs increase proportionally for each sector and used a ratio of quarterly to annual costs derived from the oil, gas, and mining engineering cost analysis to scale each sector's recommended option costs.[12] This ratio was estimated to be 2.0 and primarily reflects the increased labor costs associated with monitoring and reporting activities. As a result, quarterly reporting would lead to an increase in the total annual private sector cost from $160 million to $320 million in the first year and from $127 million to $254 million in subsequent years.

[12]Currently, this is the only industry sector available in the analysis that produced both quarterly and annual reporting cost estimates. Under the recommended option, oil, gas, and mining sectors report annually.

Table 5-14. Alternative Option 8

	Number of Reporters (covered)	$MtCO_2e$/Year (covered)	First Year Private Costs (million $2006)	Subsequent Year Private Costs (million $2006)
Recommended option	13,205	3,870	$160.4	$127.0
Alternative options				
8. Reporting is quarterly; recommended option for threshold, methodology, and verifier.	13,205	3,870	$320.8	$254.1
Absolute difference	0	0	160.4	127.0
Percentage difference	0%	0%	100.0%	100.0%

It is unclear what impact this would have on the accuracy of reported emissions. In industries where processes or fuel inputs are highly variable, increased reporting would help document the variability. However, for industries with stable processes, the impact on accuracy would likely be minimal.

5.1.6 Third-Party Verification

An alternative to having EPA QA/QC self-certified emissions based on information provided by reporting entities is to have independent third-party verification. This would lead to increased private-sector costs and potentially some reduction in Agency costs. Overall costs to society will likely be higher for a third-party verification system than for a government verification system because of increased transaction costs and lower economies of scale compared to a centralized system. As shown in Table 5-15, private-sector third-party verification costs are estimated to be approximately $58 million, compared with public-sector cost (if EPA provides verification) of $1.5 million. Table 5-16 compares this alternative with the recommended option.

Table 5-15. Private-Sector Third-Party Verification Costs

NAICS or Other Description	Number of Entities	Private: Costs per Entity ($2006)	Private: First Year Total Costs ($2006)	Public: Costs per Entity ($2006)	Public: First Year Total Costs ($2006)
Subpart A—General Provisions			$0		$0
Subpart B—Electricity Use			$0		$0
Subpart C—General Stationary Fuel Combustion Sources	3,000	$2,000	$6,000,000	$114	$342,000
Subpart D—Electricity Generation	1,108	$5,000	$5,540,000	$114	$126,312
Subpart E—Adipic Acid Production	4	$5,000	$20,000	$114	$456
Subpart F—Aluminum Production	14	$5,000	$70,000	$114	$1,596
Subpart G—Ammonia Manufacturing	24	$5,000	$120,000	$114	$2,736
Subpart H—Cement Production	107	$5,000	$535,000	$114	$12,198
Subpart I—Electronics Manufacturing	96	$5,000	$480,000	$114	$10,944
Subpart J—Ethanol Production	85	$5,000	$425,000	$114	$9,690
Subpart K—Ferroalloy Production	9	$5,000	$45,000	$114	$1,026
Subpart L—Fluorinated Gas Production	12	$5,000	$60,000	$114	$1,368
Subpart M—Food Processing	113	$5,000	$565,000	$114	$12,882
Subpart N—Glass Production	55	$5,000	$275,000	$114	$6,270
Subpart O—HCFC-22 Production	3	$5,000	$15,000	$114	$342
Subpart P—Hydrogen Production	41	$5,000	$205,000	$114	$4,674
Subpart Q—Iron and Steel Production	121	$5,000	$605,000	$114	$13,794
Subpart R—Lead Production	13	$5,000	$65,000	$114	$1,482
Subpart S—Lime Manufacturing	89	$5,000	$445,000	$114	$10,146
Subpart T—Magnesium Production	11	$5,000	$55,000	$114	$1,254
Subpart U—Miscellaneous Uses of Carbonates	0	$5,000	$0	$114	$0
Subpart V—Nitric Acid Production	45	$5,000	$225,000	$114	$5,130
Subpart W—Oil and Natural Gas Systems	1,375	$5,000	$6,875,000	$114	$156,750
Subpart X—Petrochemical Production	88	$5,000	$440,000	$114	$10,032
Subpart Y—Petroleum Refineries	150	$5,000	$750,000	$114	$17,100

(continued)

Table 5-15. Private-Sector Third-Party Verification Costs (continued)

NAICS or Other Description	Number of Entities	Private		Public	
		Costs per Entity ($2006)	First Year Total Costs ($2006)	Costs per Entity ($2006)	First Year Total Costs ($2006)
Subpart Z—Phosphoric Acid Production	14	$5,000	$70,000	$114	$1,596
Subpart AA—Pulp and Paper Manufacturing	425	$5,000	$2,125,000	$114	$48,450
Subpart BB—Silicon Carbide Production	1	$5,000	$5,000	$114	$114
Subpart CC—Soda Ash Manufacturing	5	$5,000	$25,000	$114	$570
Subpart DD—Sulfur Hexafluoride (SF6) from Electric Power Systems	141	$5,000	$705,000	$114	$16,074
Subpart EE—Titanium Dioxide Production	8	$5,000	$40,000	$114	$912
Subpart FF—Underground Coal Mines	100	$5,000	$500,000	$114	$11,400
Subpart GG—Zinc Production	5	$5,000	$25,000	$114	$570
Subpart HH—Landfills	2,551	$5,000	$12,755,000	$114	$290,814
Subpart II—Wastewater	0	$5,000	$0	$114	$0
Subpart JJ—Manure Management	43	$5,000	$215,000	$114	$4,902
Subpart KK—Suppliers of Coal and Coal-based Products and Subpart LL—Suppliers of Coal-based Liquid Fuels	1,237	$5,000	$6,185,000	$114	$141,018
Subpart MM—Suppliers of Petroleum Products	214	$5,000	$1,070,000	$114	$24,396
Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids	1,554	$5,000	$7,770,000	$114	$177,156
Subpart OO—Suppliers of Industrial Greenhouse Gases	121	$5,000	$605,000	$114	$13,794
Subpart PP—Suppliers of Carbon Dioxide (CO2)	13	$5,000	$65,000	$114	$1,482
Subpart QQ—Motor Vehicle and Engine Manufacturers	350	$5,000	$1,750,000	$114	$39,900
Total	13,205		$57,724,860		$1,521,190

A study conducted by CARB found that third-party verification costs range from $20,000 per entity for refineries to $2,000 per entity for miscellaneous facilities. The cost information was based on self-reported information by approximately 20 facilities. The costs reported by CARB were reviewed by RTI engineers and were assessed to be reasonable based on field experience. Process-related third-party verification costs varied, but averaged around $5,000 per facility. Facilities with stationary combustion sources had the lowest third-party verification costs of $2,000 per facility. In analyzing the cost of this option, we assumed that EGUs that must report their emissions under the ARP would not be subject to third-party verification requirement because their CO_2 emissions are already subject to a separate QA/QC process conducted by EPA.

Table 5-16. Alternative Option 9

	Number of Reporters (covered)	$MtCO_2e$/Year (covered)	First Year Private Costs (million $2006)	Subsequent Year Private Costs (million $2006)
Recommended option	13,205	3,870	$160.4	$127.0
Alternative options				
9. Verification is done by a third party; recommended option for threshold, methodology, and frequency.	13,205	3,870	$218.1	$184.8
Absolute difference	0	0	57.7	57.7
Percentage difference	0%	0%	36.0%	45.4%

Table 5-15 presents the private-sector and public-sector costs by NAICS associated with the third-party verification at the 25,000 CO_2e threshold. At this threshold, total private-sector costs are estimated to increase approximately $58 million, with the greatest costs associated with pipeline transportation, mining, and stationary combustion.

Public-sector (Agency) costs would likely be reduced, but it is unclear what the net impact would be. The information collection request (ICR) assumes 2 hours of EPA staff time per year will be required for EPA review and QA/QC of each report. At a labor rate of $57 per hour, this yields a total annual cost of approximately $1.5 million for EPA to review self-reported emissions.

However, under a third-party verification scenario, the Agency would bear some additional costs due to certifying verification vendors and managing the verification system. Hence, net savings to the Agency would likely be less than the $1.5 million shown above.

In addition, it is unclear if this scenario would increase the accuracy of GHG reporting. Third-party verification would most likely increase the level of detail of the QA/QC process, but it is difficult to assess what impact this would have on the accuracy of GHG reporting.

5.1.7 Only Upstream and Downstream Process Reporting

Under this scenario, unspecified stationary sources are not required to report. All other sectors are included in the definition of upstream. These include the fuel suppliers, industrial gas suppliers, industrial processes, fugitive emissions, biological processes, and vehicle and engine manufacturers sectors. Since the reporting thresholds and reporting requirements remain the same for the upstream sources, the cost estimates for sectors remain unchanged. Table 5-17 compares this alternative with the recommended option and shows that the private costs of the rule fall from $160 million to $110.5 million in the first year and fall from $127 million to $87.6 million in subsequent years. Alternative 10, first year annualized costs per metric fall from the first $0.04 to $0.03. In subsequent years, annualized cost per metric ton fall from $0.03 baseline to $0.02.

Table 5-17. Alternative Option 10

	Number of Reporters (covered)	$MtCO_2e$/Year (covered)	First Year Private Costs (million $2006)	Subsequent Year Private Costs (million $2006)
Recommended option	13,205	3,870	$160	$127
Alternative options				
10. Reporting from upstream sources only; recommended option for methodology, frequency, and verifier.	8,832	3,870	$110.5	$87.6
Absolute difference	−4,373	0	−49.9	−39.5
Percentage difference	−33%	0%	−31.1%	−31.1%

As shown in Table 5-18, over 99% of industrial processes emissions are covered at the 25,000 tCO_2e threshold for a cost of approximately $36 million. It is assumed that the uncertainly level of reported GHG emissions is unchanged under the upstream-only reporting scenario. We also report estimates of the extent to which upstream/downstream emissions may be counted more than once (Table 5-19). It should be noted that for all sources the coverage is defined as the percentage of emissions covered for that source category, except for vehicle and engine manufacturers where the coverage is defined as the percentage of manufacturers reporting out of all vehicle and engine manufacturers.

Table 5-18. Reporting Costs by Upstream and Downstream Source Categories

Upstream[1]				**Downstream[2,3,4]**			
Source Category	**# Reporters**	**Emissions Coverage (%)[10]**	**First Year Private Cost (million $2006)**	**Source Category**	**# Reporters[2]**	**Emissions Coverage[3,10] (%)**	**First Year Private Cost[3] (million $2006)**
Coal Supply	1,237	100%	$11.03	Coal[5,6] Combustion	N/A	99%	N/A
Petroleum Supply	214	100%	$1.99	Petroleum[5] Combustion[10]	N/A	20%	N/A
Natural Gas Supply	1,554	68%	$2.14	Natural Gas[5] Combustion	N/A	23%	N/A
				Sub Total Combustion	4,108	N/A[5]	$46.16
Industrial Gas Supply	133	100%	$0.41	Industrial Gas Consumption	265	28%	$3.70
				Industrial Processes	1,077	100%	$36.12
				Fugitive Emissions (coal, oil and gas)	1,475	87%	$34.86
				Biological Processes	2,792	56%	$16.59
				Vehicle[7] and Engine Manufacturers[9]	350	84%	$7.41

Notes:
[1] Most upstream facilities (e.g., coal mines, refineries) are also direct emitters of greenhouse gases, and are included in the downstream side of the table.
[2] Estimating the total number of downstream reporters by summing the rows will result in double-counting because some facilities are included in more than one row due to multiple types of emissions (e.g., facilities that burn fossil fuel and have process/fugitive/biological emissions will be included in each downstream category).
[3] The coverage and costs for downstream reporters apply to the specific source category, i.e., the fixed costs are not "double-counted" in both stationary combustion and industrial processes for the same facility.
[4] The thresholds used to determine covered facilities are additive, i.e., all of the source categories located at a facility (e.g., stationary combustion and process emissions) are added together to determine whether a facility meets the proposed threshold (e.g., 25,000 metric tons of CO_2e/yr).
[5] Estimates for the number of reporters and total cost for downstream stationary combustion do not distinguish between fuels. National level data on the number of reporters could be estimated. However, estimating the number of reporters by fuel was not possible because a single facility can combust multiple fuels. For these reasons there is not a reliable estimate of the total of the emissions coverage from the downstream stationary combustion.
[6] Approximately 90% of downstream coal combustion emissions are already reported to EPA through requirements for electricity generating units under the Acid Rain Program.
[7] Due to data limitations, the coverage for downstream sources for fuel and industrial gas consumption in this table does not take into account thresholds. Assuming full emissions coverage for each source slightly over-states the actual coverage that would result from this rule. To estimate total emissions coverage downstream, by fuel, we added total emissions resulting from the respective fuel combusted in the industrial and electricity generation sectors and divided that by total national GHG emissions from the combustion of that fuel.

[8] The percent of coverage here is percentage of vehicle and engine manufacturers covered by this proposal rather than emissions coverage. This rule proposes to collect an emissions rate for the four "transportation-related" GHG emissions (CO_2, CH_4, N_2O and HFCs). The amounts of CH_4 and N_2O are dependent on factors other than fuel characteristics such as combustion temperatures, air-fuel mixes, and use of pollution control equipment.

[9] The emissions coverage for petroleum combustion includes combustion of fuel by transportation sources as well as other uses of petroleum (e.g., home heating oil). It cannot be broken out by transportation versus other uses as there are difficulties associated with tracking which products from petroleum refiners are used for transportation fuel and which were not. We know that although refiners make these designations for the products leaving their gate, the actual end use can and does change in the market. For example, designated transportation fuel can always be used as home heating oil.

[10] Emissions coverage from the combustion of fossil fuels upstream represents CO_2 emissions only. It is not possible to estimate nitrous oxide and methane emissions without knowing where and how the fuel is combusted. In the case of downstream emissions from stationary combustion of fossil fuels, nitrous oxide and methane emissions are included in the emissions coverage estimate. They represent approximately 1% of the total emissions.

Table 5-19. Extent of Emissions Reported More than Once

Fuel or Gas		Coverage of U.S. Emissions (%)[1]	Number of Reporters[2]	Percent of U.S. Emissions Reported Both Upstream and Downstream
Coal consumption	Upstream	100%	1,237	~ 99%
	Downstream	99%	N/A	
Petroleum consumption	Upstream	100%	214	~ 20%
	Downstream	20%	N/A	
Natural gas consumption	Upstream	68%	1,554	~ 23%
	Downstream	23%	N/A	
Industrial gas consumption	Upstream	100%	133	~ 28%
	Downstream	28%	265	

[1] Due to data limitations, the coverage for downstream sources for fuel and industrial gas consumption in this table does not take into account thresholds. Assuming full emissions coverage for each source slightly over-states the actual coverage that would result from this rule.

[2] Estimates for the number of reporters and total cost for downstream stationary combustion do not distinguish between fuels. National level data on the number of reporters could be estimated. However, estimating the number of reporters by fuel was not possible because a single facility can combust multiple fuels.

[3] The total emissions covered from upstream fuel suppliers is based on the applicability requirements in the preamble that all producers of coal, petroleum and industrial gas, as well as LDCs and natural gas processing plants would be required to report to the rule. Further, all importers of fossil fuels, and industrial gas importers with potential emissions greater than 25,000 mtCO2e would be required to report. This means, 100% of potential emissions from coal, petroleum and industrial gas would be included. For natural gas, potential emissions from LDCs and gas processing plants represent about 68% of the total emissions from natural gas consumption in the United States.

In the case of downstream coverage, for coal consumption we assume we capture 99% of emissions, because we will get reporting for all coal consumed in the commercial, industrial, and electricity generating sectors. For natural gas and petroleum consumption, we assume that we capture all gas consumed in the electricity generation sector, as well as some industrial consumption. The percentages are based on reviewing data in Table 3-3 of the U.S. GHG Inventory 1990-2008.

For downstream emissions from industrial gases, we believe we are capturing emissions of these industrial gases from HCFC-22 production, magnesium production, semiconductor manufacturing, aluminum production, SF6 from electrical equipment, CO2 consumption, and N2O product uses. The downstream emissions from these sources can be found in Table ES-2 of the U.S. GHG Inventory 1990-2008 and represent 28% of emissions of these gases.

The coverage and costs for downstream reporters apply to the specific source category; therefore, fixed costs are not “double-counted” in both stationary combustion and industrial processes for the same facility. An important aspect of this scenario is that some process related emissions may not be captured due to the fact that downstream combustion sources would not be covered by the rule. A source with process emission plus combustion emissions would only have to report their process emission, thus the exclusion of downstream combustion could result in some sources being under the threshold.

5.1.8 Sensitivity of Subsequent Year Cost Estimates

National cost estimates for the recommended option were developed based on the current population of entities. Whereas production in some of the affected sectors may increase or decrease over time, it was assumed that the number of entities would remain relatively constant. Thus, the analysis assumes a stable population where all entities bear a single first-year cost and then repeated subsequent-year costs.

Due to data limitations, the coverage for downstream sources for fuel and industrial gas consumption in this table does not take into account thresholds. Assuming full emissions coverage for each source slightly over-states the actual coverage that would result from this rule. However, in reality, over time some existing entities close or go out of business and new entities come into existence. This is sometimes referred to as entry and exit in an industry. This affects the cost of the rule because as entities “turn over” the new entrants will bear first-year costs that are slightly higher than subsequent year costs. To assess the impact of this dynamic, we performed a case study analysis on selected industries in order to identify the average share of new establishments in an industry each year.

To conduct the sensitivity analysis we recomputed subsequent year costs accounting for the number of new entities census data (SBA, 2008b) suggest come into existence each year (that face first-year costs). For example, in the oil and gas extraction section, 9% of the firms in any given year are new to the industry (and hence will bear first-year costs). Thus, the adjusted subsequent-year costs are computed as

$$(0.09) \times \text{First-Year Costs} + (1 - 0.09) \times (\text{Subsequent Year Costs})$$

As shown in Table 5-20, this leads to a 1.4% increase in the subsequent-year cost estimate for the oil and gas extraction section.

We identified an estimate of each industry's new establishment share using data from the U.S. Census Statistics of U.S. Businesses (SUSB) program (SBA, 2008b). They provide an annual series that include the number of new establishments by industry.[13] Since this data is organized by NAICS, we utilized the Subpart-to-NAICS mapping provided in Table 5-2 to determine the appropriate costs to use for each NAICS industry. Using the share data in Table 5-20, we find that the subsequent-year costs are on average 2.3% higher when entry and exit of entities are taken into account. This table also lists the specific subparts utilized in estimating the costs associated with each NAICS. In some cases, it was difficult to estimate the total costs associated with each NAICS, because some subparts are mapped to several different NAICS codes and it was unclear the portion of costs associated with each. In these cases, a representative subpart was chosen.

Because of uncertainty in the future entry and exit across industries, we also performed similar calculations assuming the shares in Table 5-20 were 2% higher or lower. Under this assumption, subsequent-year costs are 2.8% higher and 1.8% higher under each case.

Consistent with the appropriations language regarding reporting of emissions from "upstream production," EPA is proposing reporting requirements from upstream suppliers of fossil fuel and industrial GHGs. In the context of GHG reporting, "upstream emissions" refers to the GHG emissions potential of a quantity of industrial gas or fossil fuel supplied into the economy. For fossil fuels, the emissions potential is the amount of CO2 that would be produced from complete combustion or oxidation of the carbon in the fuel. In many cases, the fossil fuels and industrial GHGs supplied by producers and importers are used and ultimately emitted by a large number of small sources, particularly in the commercial and residential sectors (e.g., HFCs emitted from home A/C units or GHG emissions from individual motor vehicles). To cover these direct emissions would require reporting by hundreds or thousands of small facilities. To avoid this impact, the proposed rule does not include all of those emitters, but instead requires reporting by the suppliers of industrial gases and suppliers of fossil fuels. Because the GHGs in these products are almost always fully emitted during use, reporting these supply data will provide an estimate of national emissions while substantially reducing the number of reporters. For this reason, the proposed rule requires reporting by suppliers of coal and coal-based products, petroleum products, natural gas and natural gas liquids (NGLs), CO2 gas, and other industrial GHGs.

[13] http://www.sba.gov/advo/research/data.html

Table 5-20. Estimates of the Share of New Facilities in Subsequent Years and Adjustment to Subsequent Year Costs

NAICS	Industry	Subpart	Share	First Year Private Costs ($2006)	Subsequent Year Private Costs ($2006)	Revised Subsequent Year Private Costs ($2006)	Difference ($2006)	% Difference
211	Oil and gas extraction	W	9%	$32,509,681	$28,122,153	$28,533,908	$411,754	1.5%
212	Petroleum and coal products	KK, LL, FF	8%	$13,373,254	$7,733,571	$8,185,549	$451,978	5.8%
221	SF_6 from electrical systems	DD	7%	$386,666	$386,666	$386,666	$0	0.0%
322	Pulp and paper manufacturing	AA	4%	$9,155,597	$8,961,656	$8,970,299	$8,644	0.1%
324	Petroleum and coal products	Y, MM	9%	$5,643,628	$3,545,208	$3,733,758	$188,549	5.3%
325	Chemical manufacturing	CC, E, EE, G, Y, MM, J, L, O, OO, P, V, X, Z	6%	$5,500,555	$4,313,448	$4,388,128	$74,680	1.7%
327	Cement and other mineral production	BB, H	7%	$6,938,675	$4,282,181	$4,456,412	$174,230	4.1%
331	Primary metal manufacturing	F, GG, K, Q, R, T,	8%	$19,397,314	$15,247,747	$15,561,398	$313,651	2.1%
334	Computer and electronic product manufacturing	I	7%	$3,592,915	$3,592,915	$3,592,915	$0	0.0%
335	Electrical equipment, appliance, and component manufacturing	I	6%	$3,592,915	$3,592,915	$3,592,915	$0	0.0%
486	Oil and natural gas transportation	W	12%	$32,509,681	$28,122,153	$28,661,814	$539,660	1.9%
562	Waste management and remediation services	HH	12%	$15,334,981	$10,387,538	$10,996,067	$608,529	5.9%
	Average:			$12,327,989	$9,857,346	$10,088,319	$230,973	2.3%

5.1.9 *Summary of Alternative Threshold Options*

Although, the recommended option is not the least cost option (option 3, 6, 7, and 10 are less expensive), the option provides additional benefits in terms of coverage and certainty of emissions reporting that these other options do not (see Table 5-21). For example, the higher reporting threshold under option 3 provides less emissions coverage than the recommended option. Option 5 offers similar coverage but analysis presented in 5.1.2 suggests emission estimation will be less precise. Option 6 provides only small cost labor savings (approximately 0.3 million). However, the increased cost to the public sector resulting integrating the data with the fuel quality information and issues related to maintaining data confidentiality makes it unclear whether this option will result in a net decrease in total national costs of the program. Under Option 7, the fuel suppliers' first year costs would decrease from $15 million to zero but uncertainty of the emissions estimate increases from 4% to 6%. Under option 10, some process related emissions may not be captured due to the fact that downstream combustion sources would not be covered by the rule. Source with process emission plus combustion emissions would only have to report their process emission, thus the exclusion of downstream combustion could result in some sources being under the threshold.

Table 5-21. Summary of Results by Option

Option	Number of Reporters (covered)	$MtCO_2e$/ Year (covered)	First Year Private Costs (million 2006$)	First Year Public Costs (million 2006$)	Subsequent Year Private Costs (million 2006$)	Subsequent Year Public Costs (million 2006$)
Recommended option	13,205	3,870	$160	$8	$127	$7
Alternative options						
1. A 1,000 tCO_2e threshold; recommended options for methodology, frequency, and verifier	59,587	3,951	$426	$8	$372	$7
2. A 10,000 tCO_2e threshold; recommended options for methodology, frequency, and verifier.	20,765	3,916	$213	$8	$174	$7

(continued)

Table 5-21. Summary of Results by Option (continued)

	Number of Reporters (covered)	$MtCO_2e$/ Year (covered)	First Year Private Costs (million 2006$)	First Year Public Costs (million 2006$)	Subsequent Year Private Costs (million 2006$)	Subsequent Year Public Costs (million 2006$)
3. A 100,000 tCO_2e threshold; recommended options for methodology, frequency, and verifier.	6,598	3,699	$101	$8	$79	$7
4. The measurement variable is changed to direct measurement; recommended option for threshold, frequency, and verifier.	13,205	3,870	$1,634	$8	$724	$7
5. The measurement variable is changed to default emissions factors; recommended option for threshold, frequency, and verifier.	13,205	3,870	$64	$8	$51	$7
6. Existing federal data used for measurement of fuel suppliers; recommended option for threshold, frequency, verifier, and methodology for other sources.	13,205	3,870	$160	$8	$127	$7
7. EPA uses default carbon content for fuel suppliers; recommended option for threshold, frequency, verifier, and methodology for other sources.	13,205	3,870	$145	$8	$120	$7

(continued)

Table 5-21. Summary of Results by Option (continued)

	Number of Reporters (covered)	$MtCO_2e$/ Year (covered)	First Year Private Costs (million 2006$)	First Year Public Costs (million 2006$)	Subsequent Year Private Costs (million 2006$)	Subsequent Year Public Costs (million 2006$)
8. Reporting is quarterly; recommended option for threshold, methodology, and verifier.	13,205	3,870	$321	$8	$254	$7
9. Verification is done by a third party; recommended option for threshold, methodology, and frequency.	13,205	3,870	$218	$8	$185	$7
10. Reporting from upstream sources only; recommended option for methodology, frequency, and verifier.	8,832	3,870	$110.5	$8	$87.6	$7

5.2 Assessing Economic Impacts on Small Entities

The first step in this assessment was to determine whether the rule will have a significant impact on a substantial number of small entities (SISNOSE). To make this determination, EPA used a screening analysis that allows us to indicate whether EPA can certify the rule as not having a SISNOSE. The elements of this analysis included

- identifying affected sectors and entities,
- selecting and describing the measures and economic impact thresholds used in the analysis, and
- determining SISNOSE certification category.

5.2.1 *Identify Affected Sectors and Entities*

The industry sectors covered by the rule were identified during the development of the cost analysis for the reporting rule. The SUSB data provide national information on the distribution of economic variables by industry and size.[14] These data were developed in cooperation with, and partially funded by, the Office of Advocacy of the Small Business Administration (SBA) (SBA, 2008a). The data include the number of establishments (Table 5-22), employment (Table 5-23), and receipts (Table 5-24) and present information on *all* entities in an industry covered by the rule; however, many of these entities would not be expected to report under the preferred option because they would fall below the 25,000 hybrid threshold. SUSB also provides this data by enterprise employment size. The census definitions in this data set are as follows:

- *establishmen*t: An establishment is a single physical location where business is conducted or where services or industrial operations are performed.
- *employment*: Paid employment consists of full- and part-time employees, including salaried officers and executives of corporations, who were on the payroll in the pay period including March 12. Included are employees on sick leave, holidays, and vacations; not included are proprietors and partners of unincorporated businesses.
- *receipts*: Receipts (net of taxes) are defined as the revenue for goods produced, distributed, or services provided, including revenue earned from premiums, commissions and fees, rents, interest, dividends, and royalties. Receipts exclude all revenue collected for local, state, and federal taxes.
- *enterprise*: An enterprise is a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Because the SBA's business size definitions (SBA, 2008c) apply to an establishment's "ultimate parent company," we assume in this analysis that the "enterprise" definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses and the terms are used interchangeably. We also report the SBA size standard(s) for each industry group in order to facilitate comparisons and different thresholds.

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[14] The SUSB data does not provide establishment information for agricultural NAICS codes (e.g., NAICS 112 which covers Manure Management). However, the per entity costs are small (less than $1,000 per year) and EPA believes the ultimate parent companies of entities covered are not small businesses.

Table 5-22. Number of Establishments by Affected Industry and Enterprise[a] Size: 2002

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Total Estab-lish-ments	Owned by Enterprises with:					
					1 to 20 Employees[b]	20 to 99 Employees	100 to 499 Employees	500 to 749 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Oil and Gas Extraction	211	Oil & gas extraction	500	7,629	5,239	456	292	60	64	31
Petroleum and Coal Products	212	Mining (except oil & gas)	500	7,205	2,940	1,078	671	108	136	151
SF6 from Electrical Systems and LDCs	221	Utilities	[c]	18,432	5,715	1,423	1,126	282	144	209
Pulp & Paper Manufacturing	322	Paper mfg	500 to 750	5,546	1,488	1,271	755	83	69	138
Petroleum and Coal Products	324	Petroleum & coal products mfg	[d]	2,296	596	323	292	72	82	20
Chemical Manufacturing	325	Chemical mfg	500 to 1,000	13,096	5,433	2,208	1,352	250	185	276
Cement & Other Mineral Production	327	Nonmetallic mineral product mfg	500 to 1,000	16,674	7,161	3,302	1,788	306	438	337
Primary Metal Manufacturing	331	Primary metal mfg	500 to 1,000	6,229	2,652	1,278	765	124	90	100
Computer and Electronic Product Manufacturing	334	Computer & electronic product mfg	500 to 1,000	15,883	7,709	3,435	1,497	282	130	174
Electrical Equipment, Appliance, and Component Manufacturing	335	Electrical equipment, appliance, & component mfg	500 to 1,000	6,601	3,081	1,361	628	116	80	89
Oil & Natural Gas Transportation	486	Pipeline transportation	[e]	2,701	110	59	79	115	5	42
Waste Management and Remediation Services	562	Waste management & remediation services	[f]	17,698	10,775	1,839	612	86	63	58
Adipic Acid	325199	All other basic organic chemical mfg	1,000	640	157	99	78	24	4	17
Ammonia	325311	Nitrogenous fertilizer mfg	1,000	157	78	18	15	5	1	12
Cement	327310	Cement mfg	750	253	67	29	22	11	9	20
Ferroalloys	331112	Electrometallurgical ferroalloy product mfg	750	17	3	NA	7	NA	1	1
Glass	3272	Glass & glass product mfg	500 to 1,000	2,190	1,290	276	113	13	24	16
Hydrogen Production	325120	Industrial gas mfg	1,000	551	45	20	20	NA	30	55
Iron and Steel	331112	Electrometallurgical ferroalloy product mfg	750	17	3	NA	7	NA	1	1
Lead Production	3314	Nonferrous metal (except aluminum) production & processing	750 to 1,000	958	386	174	108	24	14	11
Lime Manufacturing	327410	Lime mfg	500	77	18	13	6	7	19	4
Nitric Acid	325311	Nitrogenous fertilizer mfg	1,000	157	78	18	15	5	1	12

(continued)

Table 5-22. Number of Establishments by Affected Industry and Enterprise[a] Size: 2002 (continued)

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Total Estab-lish-ments	Owned by Enterprises with: 1 to 20 Employees[b]	20 to 99 Employees	100 to 499 Employees	500 to 749 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Petrochemical	324110	Petroleum refineries	[d]	349	85	29	28	10	7	3
Phosphoric Acid	325312	Phosphatic fertilizer mfg	500	50	12	5	6	2	NA	2
Pulp and Paper	322110	Pulp mills	750	44	8	4	7	2	2	4
Refineries	324110	Petroleum refineries	[d]	349	85	29	28	10	7	3
Silicon Carbide	327910	Abrasive product mfg	500	347	161	100	42	2	NA	NA
Soda Ash Manufacturing	3251	Basic chemical mfg	500 to 1,000	2,287	478	316	231	68	63	97
Titanium Dioxide	325188	All other basic inorganic chemical mfg	1,000	611	141	111	69	38	25	6
Zinc Production	3314	Nonferrous metal (except aluminum) production & processing	750 to 1,000	958	386	174	108	24	14	11

[a] The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Since the SBA's business size definitions (http://www.sba.gov/size) apply to an establishment's ultimate parent company, we assume in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses.

[b] Given the Agency's selected thresholds, enterprises with fewer than 20 employees are likely to be excluded from the reporting program.

[c] NAICS codes 221111, 221112, 221113, 221119, 221121, 221122—A firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours. NAICS 221210= 500 employees.

[d] 500 to 1,500. For NAICS code 324110—For purposes of Government procurement, the petroleum refiner must be a concern that has no more than 1,500 employees nor more than 125,000 barrels per calendar day total Operable Atmospheric Crude Oil Distillation capacity. Capacity includes owned or leased facilities as well as facilities under a processing agreement or an arrangement such as an exchange agreement or a throughput. The total product to be delivered under the contract must be at least 90% refined by the successful bidder from either crude oil or bona fide feedstocks.

[e] NAICS codes 486110 = 1,500 employees; NAICS 486210=$6.5 million annual receipts; NAICS 486910 = 1,500 employees; and NAICS 486990 =$11.5 million annual receipts.

[f] Ranges from $6.5 to $13.0 million annual receipts; Environmental Remediation services has a 500 employee definition and the following criteria. NAICS 562910—Environmental Remediation Services:

a) For SBA assistance as a small business concern in the industry of Environmental Remediation Services, other than for Government procurement, a concern must be engaged primarily in furnishing a range of services for the remediation of a contaminated environment to an acceptable condition including, but not limited to, preliminary assessment, site inspection, testing, remedial investigation, feasibility studies, remedial design, containment, remedial action, removal of contaminated materials, storage of contaminated materials and security and site closeouts. If one of such activities accounts for 50% or more of a concern's total revenues, employees, or other related factors, the concern's primary industry is that of the particular industry and not the Environmental Remediation Services Industry.

b) For purposes of classifying a Government procurement as Environmental Remediation Services, the general purpose of the procurement must be to restore a contaminated environment and also the procurement must be composed of activities in three or more separate industries with separate NAICS codes or, in some instances (e.g., engineering), smaller sub-components of NAICS codes with separate, distinct size standards. These activities may include, but are not limited to, separate activities in industries such as: Heavy Construction; Special Trade Construction; Engineering Services; Architectural Services; Management Services; Refuse Systems; Sanitary Services, Not Elsewhere Classified; Local Trucking Without Storage; Testing Laboratories; and Commercial, Physical and Biological Research. If any activity in the procurement can be identified with a separate NAICS code, or component of a code with a separate distinct size standard, and that industry accounts for 50% or more of the value of the entire procurement, then the proper size standard is the one for that particular industry, and not the Environmental Remediation Service size standard.

NA: Not available. SUSB did not report this data for disclosure or other reasons.

Table 5-23. Number of Employees by Affected Industry and Enterprise[a] Size: 2002

			SBA Size	Total	Owned by Enterprises with:

Industry	NAICS	NAICS Description	Standard (effective March 11, 2008)	Employees	1 to 20 Employees[b]	20 to 99 Employees	100 to 499 Employees	500 to 749 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Oil and Gas Extraction	211	Oil & gas extraction	500	88,280	19,336	12,113	11,656	2,421	3,551	1,061
Petroleum and Coal Products	212	Mining (except oil & gas)	500	194,174	18,243	30,356	28,607	5,673	6,305	6,758
SF6 from Electrical Systems and LDCS	221	Utilities	[c]	648,254	24,257	39,391	46,942	12,042	6,519	14,653
Pulp & Paper Manufacturing	322	Paper mfg	500 to 750	495,990	11,325	52,334	78,402	13,293	12,496	23,283
Petroleum and Coal Products	324	Petroleum & coal products mfg	[d]	100,403	3,709	8,319	10,337	3,606	1,268	1,521
Chemical Manufacturing	325	Chemical mfg	500 to 1,000	827,430	34,838	78,090	113,326	28,025	18,119	28,338
Cement & Other Mineral Production	327	Nonmetallic mineral product mfg	500 to 1,000	475,476	47,315	98,637	85,569	17,516	17,946	17,512
Primary Metal Manufacturing	331	Primary metal mfg	500 to 1,000	501,038	18,299	52,242	94,040	21,868	18,062	17,252
Computer and Electronic Product Manufacturing	334	Computer & electronic product mfg	500 to 1,000	1,300,411	50,279	139,966	186,772	53,138	33,589	43,361
Electrical Equipment, Appliance, and Component Manufacturing	335	Electrical equipment, appliance, & component mfg	500 to 1,000	502,400	19,997	55,428	75,464	20,176	16,714	17,744
Oil & Natural Gas Transportation	486	Pipeline transportation	[e]	50,362	588	227	569	NA	NA	NA
Waste Management and Remediation Services	562	Waste management & remediation services	[f]	300,580	56,529	59,245	37,530	5,122	3,401	3,645
Adipic Acid	325199	All other basic organic chemical mfg	1,000	73,342	1,023	2,412	3,232	NA	754	NA
Ammonia	325311	Nitrogenous fertilizer mfg	1,000	4,949	363	210	NA	NA	NA	NA
Cement	327310	Cement mfg	750	16,905	493	418	1,157	NA	NA	2,051
Ferroalloys	331112	Electrometallurgical ferroalloy product mfg	750	2,266	NA	NA	NA	NA	NA	NA
Glass	3272	Glass & glass product mfg	500 to 1,000	114,794	6,563	10,569	13,186	1,741	2,622	2,877
Hydrogen Production	325120	Industrial gas mfg	1,000	9,557	88	294	510	NA	NA	NA
Iron and Steel	331112	Electrometallurgical ferroalloy product mfg	750	2,266	NA	NA	NA	NA	NA	NA
Lead Production	3314	Nonferrous metal (except aluminum) production & processing	750 to 1,000	64,203	2,421	6,680	10,407	NA	NA	1,337
Lime Manufacturing	327410	Lime mfg	500	4,393	33	227	NA	NA	NA	NA

(continued)

Table 5-23. Number of Employees by Affected Industry and Enterprise[a] Size: 2002 (continued)

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Total Employees	Owned by Enterprises with: 1 to 20 Employees[b]	20 to 99 Employees	100 to 499 Employees	500 to 749 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Nitric Acid	325311	Nitrogenous fertilizer mfg	1,000	4,949	363	210	NA	NA	NA	NA
Petrochemical	324110	Petroleum refineries	[d]	62,132	454	942	2,870	2,903	NA	NA
Phosphoric Acid	325312	Phosphatic fertilizer mfg	500	6,288	27	NA	NA	NA	NA	NA
Pulp and Paper	322110	Pulp mills	750	8,373	22	NA	NA	NA	NA	NA
Refineries	324110	Petroleum refineries	[d]	62,132	454	942	2,870	2,903	NA	NA
Silicon Carbide	327910	Abrasive product mfg	500	16,079	1,237	3,637	3,536	NA	NA	NA
Soda Ash Manufacturing	3251	Basic chemical mfg	500 to 1,000	172,964	3,171	10,392	16,525	5,548	3,354	5,001
Titanium Dioxide	325188	All other basic inorganic chemical mfg	1,000	49,845	566	881	1,839	NA	NA	NA
Zinc Production	3314	Nonferrous metal (except aluminum) production & processing	750 to 1,000	64,203	2,421	6,680	10,407	NA	NA	1,337

[a] The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Since the SBA's business size definitions (http://www.sba.gov/size) apply to an establishment's ultimate parent company, we assume in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses.

[b] Given the Agency's selected thresholds, enterprises with fewer than 20 employees are likely to be excluded from the reporting program.

[c] NAICS codes 221111, 221112, 221113, 221119, 221121, 221122—A firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours. NAICS 221210=500 employees.

[d] 500 to 1,500. For NAICS code 324110—For purposes of Government procurement, the petroleum refiner must be a concern that has no more than 1,500 employees nor more than 125,000 barrels per calendar day total Operable Atmospheric Crude Oil Distillation capacity. Capacity includes owned or leased facilities as well as facilities under a processing agreement or an arrangement such as an exchange agreement or a throughput. The total product to be delivered under the contract must be at least 90% refined by the successful bidder from either crude oil or bona fide feedstocks.

[e] NAICS codes 486110 = 1,500 employees; NAICS 486210=$6.5 million annual receipts; NAICS 486910 = 1,500 employees; and NAICS 486990 =$11.5 million annual receipts.

[f] Ranges from $6.5 to $13.0 million annual receipts; Environmental Remediation services has a 500 employee definition and the following criteria. NAICS 562910—Environmental Remediation Services:

a) For SBA assistance as a small business concern in the industry of Environmental Remediation Services, other than for Government procurement, a concern must be engaged primarily in furnishing a range of services for the remediation of a contaminated environment to an acceptable condition including, but not limited to, preliminary assessment, site inspection, testing, remedial investigation, feasibility studies, remedial design, containment, remedial action, removal of contaminated materials, storage of contaminated materials and security and site closeouts. If one of such activities accounts for 50% or more of a concern's total revenues, employees, or other related factors, the concern's primary industry is that of the particular industry and not the Environmental Remediation Services Industry.

b) For purposes of classifying a Government procurement as Environmental Remediation Services, the general purpose of the procurement must be to restore a contaminated environment and also the procurement must be composed of activities in three or more separate industries with separate NAICS codes or, in some instances (e.g., engineering), smaller sub-components of NAICS codes with separate, distinct size standards. These activities may include, but are not limited to, separate activities in industries such as: Heavy Construction; Special Trade Construction; Engineering Services; Architectural Services; Management Services; Refuse Systems; Sanitary Services, Not Elsewhere Classified; Local Trucking Without Storage; Testing Laboratories; and Commercial, Physical and Biological Research. If any activity in the procurement can be identified with a separate NAICS code, or component of a code with a separate distinct size standard, and that industry accounts for 50% or more of the value of the entire procurement, then the proper size standard is the one for that particular industry, and not the Environmental Remediation Service size standard.

NA: Not available. SUSB did not report this data for disclosure or other reasons.

Table 5-24. Receipts by Affected Industry and Enterprise[a] Size: 2002

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Total Receipts (million)	Owned by Enterprises with: 1 to 20 Employees[b]	20 to 99 Employees	100 to 499 Employees	500 to 749 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Oil and Gas Extraction	211	Oil & gas extraction	500	$160,879	$7,345	$6,790	$9,609	$4,609	$3,991	$2,805
Petroleum and Coal Products	212	Mining (except oil & gas)	500	$47,733	$2,705	$5,381	$6,423	$1,583	$1,526	$1,846
SF6 from Electrical Systems and LDCs	221	Utilities	[c]	$396,077	$8,958	$24,519	$25,258	$7,394	$4,521	$9,567
Pulp & Paper Manufacturing	322	Paper mfg	500 to 750	$154,746	$2,218	$9,483	$17,620	$3,034	$3,951	$6,798
Petroleum and Coal Products	324	Petroleum & coal products mfg	[d]	$216,624	$1,837	$5,528	$7,754	$9,279	$975	$1,115
Chemical Manufacturing	325	Chemical mfg	500 to 1,000	$468,211	$9,631	$21,394	$39,111	$12,217	$7,324	$14,762
Cement & Other Mineral Production	327	Nonmetallic mineral product mfg	500 to 1,000	$95,443	$6,446	$15,357	$14,722	$3,604	$3,470	$3,789
Primary Metal Manufacturing	331	Primary metal mfg	500 to 1,000	$139,461	$2,847	$8,931	$18,904	$4,829	$6,201	$5,254
Computer and Electronic Product Manufacturing	334	Computer & electronic product mfg	500 to 1,000	$379,931	$8,578	$22,791	$36,140	$12,442	$7,452	$11,275
Electrical Equipment, Appliance, and Component Manufacturing	335	Electrical equipment, appliance, & component mfg	500 to 1,000	$108,523	$3,440	$8,504	$12,413	$4,205	$3,976	$4,648
Oil & Natural Gas Transportation	486	Pipeline transportation	[e]	$45,053	$1,009	$137	$224	NA	NA	NA
Waste Management and Remediation Services	562	Waste management & remediation services	[f]	$48,204	$6,465	$7,259	$5,153	$837	$745	$509
Adipic Acid	325199	All other basic organic chemical mfg	1,000	$46,874	$379	$764	$1,837	NA	$854	NA
Ammonia	325311	Nitrogenous fertilizer mfg	1,000	$3,335	$132	$52	NA	NA	NA	NA
Cement	327310	Cement mfg	750	$7,252	$180	$104	$456	NA	NA	$861
Ferroalloys	331112	Electrometallurgical ferroalloy product mfg	750	$875	NA	NA	NA	NA	NA	NA
Glass	3272	Glass & glass product mfg	500 to 1,000	$22,180	$689	$1,252	$1,786	$321	$313	$382
Hydrogen Production	325120	Industrial gas mfg	1,000	$5,780	$22	$292	$71	NA	NA	NA
Iron and Steel	331112	Electrometallurgical ferroalloy product mfg	750	$875	NA	NA	NA	NA	NA	NA
Lead Production	3314	Nonferrous metal (except aluminum) production & processing	750 to 1,000	$21,330	$505	$2,075	$2,609	NA	NA	$315
Lime Manufacturing	327410	Lime mfg	500	$1,018	$6	$55	NA	NA	NA	NA
Nitric Acid	325311	Nitrogenous fertilizer mfg	1,000	$3,335	$132	$52	NA	NA	NA	NA

(continued)

Table 5-24. Receipts by Affected Industry and Enterprise[a] Size: 2002 (continued)

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Total Receipts (million)	Owned by Enterprises with: 1 to 20 Employees[b]	20 to 99 Employees	100 to 499 Employees	500 to 749 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Petrochemical	324110	Petroleum refineries	[d]	$195,752	$467	$2,519	$4,500	$8,758	NA	NA
Phosphoric Acid	325312	Phosphatic fertilizer mfg	500	$3,997	$6	NA	NA	NA	NA	NA
Pulp and Paper	322110	Pulp mills	750	$3,791	$10	NA	NA	NA	NA	NA
Refineries	324110	Petroleum refineries	[d]	$195,752	$467	$2,519	$4,500	$8,758	NA	NA
Silicon Carbide	327910	Abrasive product mfg	500	$3,350	$179	$486	$621	NA	NA	NA
Soda Ash Manufacturing	3251	Basic chemical mfg	500 to 1,000	$107,018	$1,391	$4,097	$6,918	$3,462	$1,777	$3,313
Titanium Dioxide	325188	All other basic inorganic chemical mfg	1,000	$16,314	$173	$232	$594	NA	NA	NA
Zinc Production	3314	Nonferrous metal (except aluminum) production & processing	750 to 1,000	$21,330	$505	$2,075	$2,609	NA	NA	$315

[a] The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Since the SBA's business size definitions (http://www.sba.gov/size) apply to an establishment's ultimate parent company, we assume in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses.

[b] Given the Agency's selected thresholds, enterprises with fewer than 20 employees are likely to be excluded from the reporting program.

[c] NAICS codes 221111, 221112, 221113, 221119, 221121, 221122—A firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours. NAICS 221210=500 employees.

[d] 500 to 1,500. For NAICS code 324110—For purposes of Government procurement, the petroleum refiner must be a concern that has no more than 1,500 employees nor more than 125,000 barrels per calendar day total Operable Atmospheric Crude Oil Distillation capacity. Capacity includes owned or leased facilities as well as facilities under a processing agreement or an arrangement such as an exchange agreement or a throughput. The total product to be delivered under the contract must be at least 90% refined by the successful bidder from either crude oil or bona fide feedstocks.

[e] NAICS codes 486110 = 1,500 employees; NAICS 486210=$6.5 million annual receipts; NAICS 486910 = 1,500 employees; and NAICS 486990 =$11.5 million annual receipts.

[f] Ranges from $6.5 to $13.0 million annual receipts; Environmental Remediation services has a 500 employee definition and the following criteria. NAICS 562910—Environmental Remediation Services:

a) For SBA assistance as a small business concern in the industry of Environmental Remediation Services, other than for Government procurement, a concern must be engaged primarily in furnishing a range of services for the remediation of a contaminated environment to an acceptable condition including, but not limited to, preliminary assessment, site inspection, testing, remedial investigation, feasibility studies, remedial design, containment, remedial action, removal of contaminated materials, storage of contaminated materials and security and site closeouts. If one of such activities accounts for 50% or more of a concern's total revenues, employees, or other related factors, the concern's primary industry is that of the particular industry and not the Environmental Remediation Services Industry.

b) For purposes of classifying a Government procurement as Environmental Remediation Services, the general purpose of the procurement must be to restore a contaminated environment and also the procurement must be composed of activities in three or more separate industries with separate NAICS codes or, in some instances (e.g., engineering), smaller sub-components of NAICS codes with separate, distinct size standards. These activities may include, but are not limited to, separate activities in industries such as: Heavy Construction; Special Trade Construction; Engineering Services; Architectural Services; Management Services; Refuse Systems; Sanitary Services, Not Elsewhere Classified; Local Trucking Without Storage; Testing Laboratories; and Commercial, Physical and Biological Research. If any activity in the procurement can be identified with a separate NAICS code, or component of a code with a separate distinct size standard, and that industry accounts for 50% or more of the value of the entire procurement, then the proper size standard is the one for that particular industry, and not the Environmental Remediation Service size standard.

NA: Not available. SUSB did not report this data disclosure or other reasons.

5.2.2 Develop Small Entity Economic Impact Measures

Because the rule covers a large number of sectors and primarily covers businesses, the analysis generated a set of sales tests (represented as cost-to-receipt ratios)[15] for NAICS codes associated with the affected sectors. Although the appropriate SBA size definition should be applied at the parent company (enterprise) level, data limitations allowed us only to compute and compare ratios for a *model establishment* for six *enterprise size* ranges (i.e., all categories, enterprises with 1 to 20 employees, 20 to 99 employees, 100 to 499 employees, 500 to 999 employees, and 1,000 to 1,499 employees. This approach allows us to account for differences in establishment receipts between large and small enterprises and differences in small business definitions across affected industries. It is also a conservative approach, because an establishment's parent company (the "enterprise") may have other economic resources that could be used to cover the costs of the reporting program.

These sales tests examine the average establishment's total annualized mandatory reporting costs to the average establishment receipts for enterprises within several employment categories[16] (first year costs: Table 5-25; subsequent year costs: Table 5-26). The average entity costs used to compute the sales test are the same across all of these enterprise size categories. As a result, the sales-test will overstate the cost-to-receipt ratio for establishments owned by small businesses, because the reporting costs are likely lower than average entity estimates provided by the engineering cost analysis.

The rule also covers sectors that could conceptually include entities owned by small governments. However, given the uncertainty and data limitations associated with identifying and appropriately classifying these entities, we computed a "revenue" test for a model small government, where the annualized compliance cost is a percentage of annual government revenues (U.S. Census, 2005a and b). For example, from the 2002 Census (in $2006), revenues for small governments (counties and municipalities) with populations fewer than 10,000 are $3 million, and revenues for local governments with populations fewer than 50,000 is $7 million. As an upper bound estimate, summing typical per-respondent costs of combustion plus landfills

[15]The following metrics for other small entity economic impact measures (if applicable) would potentially include

- Small governments (if applicable): "Revenue" test; annualized compliance cost as a percentage of annual government revenues
- Small non-profits (if applicable): "Expenditure" test; annualized compliance cost as a percentage of annual operating expenses

[16]For the one to 20 employee category, we exclude SUSB data for enterprises with zero employees. These enterprises did not operate the entire year.

Table 5-25. Establishment Sales Tests by Industry and Enterprise[a] Size: First Year Costs

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Average Cost Per Entity ($1,000/ entity)	All Enter-prises	Owned by Enterprises with: 1 to 20 Employ-ees[b]	20 to 99 Employ-ees	100 to 499 Employ-ees	500 to 749 Employ-ees	750 to 999 Employ-ees	1,000 to 1,499 Employ-ees
Oil and Gas Extraction	211	Oil & gas extraction	500	$23	0.1%	1.5%	0.1%	0.1%	0.0%	0.0%	0.0%
Petroleum and Coal Products	212	Mining (except oil & gas)	500	$10	0.1%	0.9%	0.2%	0.1%	0.1%	0.1%	0.1%
SF6 from Electrical Systems and LDCs	221	Utilities	[c]	$1	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Pulp & Paper Manufacturing	322	Paper mfg	500 to 750	$22	0.1%	1.3%	0.3%	0.1%	0.1%	0.0%	0.0%
Petroleum and Coal Products	324	Petroleum & coal products mfg	[d]	$16	0.0%	0.4%	0.1%	0.1%	0.0%	0.1%	0.0%
Chemical Manufacturing	325	Chemical mfg	500 to 1,000	$12	0.0%	0.6%	0.1%	0.0%	0.0%	0.0%	0.0%
Cement & Other Mineral Production	327	Nonmetallic mineral product mfg	500 to 1,000	$51	0.8%	4.9%	1.0%	0.5%	0.4%	0.6%	0.4%
Primary Metal Manufacturing	331	Primary metal mfg	500 to 1,000	$112	0.4%	9.1%	1.4%	0.4%	0.2%	0.1%	0.2%
Computer and Electronic Product Manufacturing	334	Computer & electronic product mfg	500 to 1,000	$37	0.1%	2.9%	0.5%	0.1%	0.1%	0.1%	0.1%
Electrical Equipment, Appliance, and Component Manufacturing	335	Electrical equipment, appliance, & component mfg	500 to 1,000	$37	0.2%	2.9%	0.5%	0.2%	0.1%	0.1%	0.1%
Oil & Natural Gas Transportation	486	Pipeline transportation	[e]	$12	0.1%	0.1%	0.4%	0.4%	NA	NA	NA
Waste Management and Remediation Services	562	Waste management & remediation services	[f]	$6	0.2%	0.9%	0.1%	0.1%	0.1%	0.0%	0.1%
Adipic Acid	325199	All other basic organic chemical mfg	1,000	$24	0.0%	0.9%	0.3%	0.1%	NA	0.0%	NA
Ammonia	325311	Nitrogenous fertilizer mfg	1,000	$19	0.1%	1.0%	0.6%	NA	NA	NA	NA
Cement	327310	Cement mfg	750	$65	0.2%	2.1%	1.6%	0.3%	NA	NA	0.1%
Ferroalloys	331112	Electrometallurgical ferroalloy product mfg	750	$28	0.0%	NA	NA	NA	NA	NA	NA
Glass	3272	Glass & glass product mfg	500 to 1,000	$11	0.1%	1.7%	0.2%	0.1%	0.0%	0.1%	0.0%
Hydrogen Production	325120	Industrial gas mfg	1,000	$3	0.0%	0.6%	0.0%	0.1%	NA	NA	NA
Iron and Steel	331112	Electrometallurgical ferroalloy product mfg	750	$150	0.3%	NA	NA	NA	NA	NA	NA
Lead Production	3314	Nonferrous metal (except aluminum) production & processing	750 to 1,000	$23	0.1%	1.5%	0.2%	0.1%	NA	NA	0.1%
Lime Manufacturing	327410	Lime mfg	500	$60	0.4%	16.5%	1.2%	NA	NA	NA	NA
Nitric Acid	325311	Nitrogenous fertilizer mfg	1,000	$20	0.1%	1.0%	0.6%	NA	NA	NA	NA
Petrochemical	324110	Petroleum refineries	[d]	$19	0.0%	0.3%	0.0%	0.0%	0.0%	NA	NA

(continued)

Table 5-25. Establishment Sales Tests by Industry and Enterprise[a] Size: First Year Costs (continued)

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Average Cost Per Entity ($1,000/ entity)	All Enterprises	Owned by Enterprises with: 1 to 20 Employees[b]	20 to 99 Employees	100 to 499 Employees	500 to 749 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Phosphoric Acid	325312	Phosphatic fertilizer mfg	500	$60	0.1%	10.1%	NA	NA	NA	NA	NA
Pulp and Paper	322110	Pulp mills	750	$22	0.0%	1.5%	NA	NA	NA	NA	NA
Refineries	324110	Petroleum refineries	[d]	$24	0.0%	0.4%	0.0%	0.0%	0.0%	NA	NA
Silicon Carbide	327910	Abrasive product mfg	500	$11	0.1%	0.8%	0.2%	0.1%	NA	NA	NA
Soda Ash Manufacturing	3251	Basic chemical mfg	500 to 1,000	$9	0.0%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%
Titanium Dioxide	325188	All other basic inorganic chemical mfg	1,000	$9	0.0%	0.7%	0.4%	0.1%	NA	NA	NA
Zinc Production	3314	Nonferrous metal (except aluminum) production & processing	750 to 1,000	$19	0.1%	1.2%	0.1%	0.1%	NA	NA	0.1%

[a] The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Since the SBA's business size definitions (http://www.sba.gov/size) apply to an establishment's ultimate parent company, we assume in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses.

[b] Given the Agency's selected thresholds, enterprises with fewer than 20 employees are likely to be excluded from the reporting program.

[c] NAICS codes 221111, 221112, 221113, 221119, 221121, 221122—A firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours. NAICS 221210=500 employees.

[d] 500 to 1,500. For NAICS code 324110—For purposes of Government procurement, the petroleum refiner must be a concern that has no more than 1,500 employees nor more than 125,000 barrels per calendar day total Operable Atmospheric Crude Oil Distillation capacity. Capacity includes owned or leased facilities as well as facilities under a processing agreement or an arrangement such as an exchange agreement or a throughput. The total product to be delivered under the contract must be at least 90% refined by the successful bidder from either crude oil or bona fide feedstocks.

[e] NAICS codes 486110 = 1,500 employees; NAICS 486210=$6.5 million annual receipts; NAICS 486910 = 1,500 employees; and NAICS 486990 =$11.5 million annual receipts.

[f] Ranges from $6.5 to $13.0 million annual receipts; Environmental Remediation services has a 500 employee definition and the following criteria. NAICS 562910—Environmental Remediation Services:

a) For SBA assistance as a small business concern in the industry of Environmental Remediation Services, other than for Government procurement, a concern must be engaged primarily in furnishing a range of services for the remediation of a contaminated environment to an acceptable condition including, but not limited to, preliminary assessment, site inspection, testing, remedial investigation, feasibility studies, remedial design, containment, remedial action, removal of contaminated materials, storage of contaminated materials and security and site closeouts. If one of such activities accounts for 50% or more of a concern's total revenues, employees, or other related factors, the concern's primary industry is that of the particular industry and not the Environmental Remediation Services Industry.

b) For purposes of classifying a Government procurement as Environmental Remediation Services, the general purpose of the procurement must be to restore a contaminated environment and also the procurement must be composed of activities in three or more separate industries with separate NAICS codes or, in some instances (e.g., engineering), smaller sub-components of NAICS codes with separate, distinct size standards. These activities may include, but are not limited to, separate activities in industries such as: Heavy Construction; Special Trade Construction; Engineering Services; Architectural Services; Management Services; Refuse Systems; Sanitary Services, Not Elsewhere Classified; Local Trucking Without Storage; Testing Laboratories; and Commercial, Physical and Biological Research. If any activity in the procurement can be identified with a separate NAICS code, or component of a code with a separate distinct size standard, and that industry accounts for 50% or more of the value of the entire procurement, then the proper size standard is the one for that particular industry, and not the Environmental Remediation Service size standard.

NA: Not available. SUSB did not report the data necessary to calculate this ratio.

Table 5-26. Establishment Sales Tests by Industry and Enterprise[a] Size: Subsequent Year Costs

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Average Cost Per Entity ($/entity)	All Enterprises	Owned by Enterprises with: 1 to 20 Employees[b]	20 to 99 Employees	100 to 499 Employees	500 to 749 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Oil and Gas Extraction	211	Oil & gas extraction	500	$23	0.1%	1.5%	0.1%	0.1%	0.0%	0.0%	0.0%
Petroleum and Coal Products	212	Mining (except oil & gas)	500	$10	0.1%	0.9%	0.2%	0.1%	0.1%	0.1%	0.1%
SF6 from Electrical Systems and LDCs	221	Utilities	[c]	$1	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Pulp & Paper Manufacturing	322	Paper mfg	500 to 750	$22	0.1%	1.3%	0.3%	0.1%	0.1%	0.0%	0.0%
Petroleum and Coal Products	324	Petroleum & coal products mfg	[d]	$16	0.0%	0.4%	0.1%	0.1%	0.0%	0.1%	0.0%
Chemical Manufacturing	325	Chemical mfg	500 to 1,000	$12	0.0%	0.6%	0.1%	0.0%	0.0%	0.0%	0.0%
Cement & Other Mineral Production	327	Nonmetallic mineral product mfg	500 to 1,000	$51	0.8%	4.9%	1.0%	0.5%	0.4%	0.6%	0.4%
Primary Metal Manufacturing	331	Primary metal mfg	500 to 1,000	$112	0.4%	9.1%	1.4%	0.4%	0.2%	0.1%	0.2%
Computer and Electronic Product Manufacturing	334	Computer & electronic product mfg	500 to 1,000	$37	0.1%	2.9%	0.5%	0.1%	0.1%	0.1%	0.1%
Electrical Equipment, Appliance, and Component Manufacturing	335	Electrical equipment, appliance, & component mfg	500 to 1,000	$37	0.2%	2.9%	0.5%	0.2%	0.1%	0.1%	0.1%
Oil & Natural Gas Transportation	486	Pipeline transportation	[e]	$12	0.1%	0.1%	0.4%	0.4%	NA	NA	NA
Waste Management and Remediation Services	562	Waste management & remediation services	[f]	$6	0.2%	0.9%	0.1%	0.1%	0.1%	0.0%	0.1%
Adipic Acid	325199	All other basic organic chemical mfg	1,000	$24	0.0%	0.9%	0.3%	0.1%	NA	0.0%	NA
Ammonia	325311	Nitrogenous fertilizer mfg	1,000	$19	0.1%	1.0%	0.6%	NA	NA	NA	NA
Cement	327310	Cement mfg	750	$65	0.2%	2.1%	1.6%	0.3%	NA	NA	0.1%
Ferroalloys	331112	Electrometallurgical ferroalloy product mfg	750	$28	0.0%	NA	NA	NA	NA	NA	NA
Glass	3272	Glass & glass product mfg	500 to 1,000	$11	0.1%	1.7%	0.2%	0.1%	0.0%	0.1%	0.0%
Hydrogen Production	325120	Industrial gas mfg	1,000	$3	0.0%	0.6%	0.0%	0.1%	NA	NA	NA
Iron and Steel	331112	Electrometallurgical ferroalloy product mfg	750	$150	0.3%	NA	NA	NA	NA	NA	NA
Lead Production	3314	Nonferrous metal (except aluminum) production & processing	750 to 1,000	$23	0.1%	1.5%	0.2%	0.1%	NA	NA	0.1%

(continued)

Table 5-26. Establishment Sales Tests by Industry and Enterprise[a] Size: Subsequent Year Costs (continued)

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Average Cost Per Entity ($/entity)	All Enterprises	Owned by Enterprises with: 1 to 20 employees[b]	20 to 99 employees	100 to 499 employees	500 to 749 employees	750 to 999 employees	1,000 to 1,499 employees
Lime Manufacturing	327410	Lime mfg	500	$60	0.4%	16.5%	1.2%	NA	NA	NA	NA
Nitric Acid	325311	Nitrogenous fertilizer mfg	1,000	$20	0.1%	1.0%	0.6%	NA	NA	NA	NA
Petrochemical	324110	Petroleum refineries	d	$19	0.0%	0.3%	0.0%	0.0%	0.0%	NA	NA
Phosphoric Acid	325312	Phosphatic fertilizer mfg	500	$60	0.1%	10.1%	NA	NA	NA	NA	NA
Pulp and Paper	322110	Pulp mills	750	$22	0.0%	1.5%	NA	NA	NA	NA	NA
Refineries	324110	Petroleum refineries	d	$24	0.0%	0.4%	0.0%	0.0%	0.0%	NA	NA
Silicon Carbide	327910	Abrasive product mfg	500	$11	0.1%	0.8%	0.2%	0.1%	NA	NA	NA
Soda Ash Manufacturing	3251	Basic chemical mfg	500 to 1,000	$9	0.0%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%
Titanium Dioxide	325188	All other basic inorganic chemical mfg	1,000	$9	0.0%	0.7%	0.4%	0.1%	NA	NA	NA
Zinc Production	3314	Nonferrous metal (except aluminum) production & processing	750 to 1,000	$19	0.1%	1.2%	0.1%	0.1%	NA	NA	0.1%

[a] The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Since the SBA's business size definitions (http://www.sba.gov/size) apply to an establishment's ultimate parent company, we assume in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses.

[b] Given the Agency's selected thresholds, enterprises with fewer than 20 employees are likely to be excluded from the reporting program.

[c] NAICS codes 221111, 221112, 221113, 221119, 221121, 221122—A firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours. NAICS 221210 = 500 employees.

[d] 500 to 1,500. For NAICS code 324110—For purposes of Government procurement, the petroleum refiner must be a concern that has no more than 1,500 employees nor more than 125,000 barrels per calendar day total Operable Atmospheric Crude Oil Distillation capacity. Capacity includes owned or leased facilities as well as facilities under a processing agreement or an arrangement such as an exchange agreement or a throughput. The total product to be delivered under the contract must be at least 90% refined by the successful bidder from either crude oil or bona fide feedstocks.

[e] NAICS codes 486110 = 1,500 employees; NAICS 486210 = $6.5 million annual receipts; NAICS 486910 = 1,500 employees; and NAICS 486990 = $11.5 million annual receipts.

[f] Ranges from $6.5 to $13.0 million annual receipts; Environmental Remediation services has a 500 employee definition and the following criteria. NAICS 562910—Environmental Remediation Services:

a) For SBA assistance as a small business concern in the industry of Environmental Remediation Services, other than for Government procurement, a concern must be engaged primarily in furnishing a range of services for the remediation of a contaminated environment to an acceptable condition including, but not limited to, preliminary assessment, site inspection, testing, remedial investigation, feasibility studies, remedial design, containment, remedial action, removal of contaminated materials, storage of contaminated materials and security and site closeouts. If one of such activities accounts for 50% or more of a concern's total revenues, employees, or other related factors, the concern's primary industry is that of the particular industry and not the Environmental Remediation Services Industry.

b) For purposes of classifying a Government procurement as Environmental Remediation Services, the general purpose of the procurement must be to restore a contaminated environment and also the procurement must be composed of activities in three or more separate industries with separate NAICS codes or, in some instances (e.g., engineering), smaller sub-components of NAICS codes with separate, distinct size standards. These activities may include, but are not limited to, separate activities in industries such as: Heavy Construction; Special Trade Construction; Engineering Services; Architectural Services; Management Services; Refuse Systems; Sanitary Services, Not Elsewhere Classified; Local Trucking Without Storage; Testing Laboratories; and Commercial, Physical and Biological Research. If any activity in the procurement can be identified with a separate NAICS code, or component of a code with a separate distinct size standard, and that industry accounts for 50% or more of the value of the entire procurement, then the proper size standard is the one for that particular industry, and not the Environmental Remediation Service size standard.

NA: Not available. SUSB did not report the data necessary to calculate this ratio.

plus natural gas suppliers yields a cost of approximately $17,000 per local government in the first year. Thus, for the smallest group of local governments (<10,000 people), cost-to-revenue ratio would be 0.8%. For the larger group of governments (<50,000 people), the cost-to-revenue ratio is 0.3%.

5.2.3 Results of Screening Analysis

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

For the purposes of assessing the impacts of the proposed rule on small entities, we defined a small entity as (1) a small business, as defined by SBA's regulations at 13 CFR Part 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

EPA believes the proposed thresholds maximize the rule coverage with over 85% of U.S. emissions reported by approximately 13,205 reporters, while keeping reporting burden to a minimum and excluding small emitters. Furthermore, many industry stakeholders with whom EPA met expressed support for a 25,000 metric ton of CO_2e threshold because it sufficiently captures the majority of GHG emissions in the United States while excluding smaller facilities and sources. For small facilities that are captured by the rule, EPA has proposed simplified emission estimation methods where feasible (e.g., stationary combustion equipment under a certain rating can use a simplified mass balance approach as opposed to more rigorous direct monitoring) to keep the burden of reporting as low as possible. For further detail on the rationale for excluding small entities through threshold selection, please see the threshold TSD.

After considering the economic impact of the proposed rule on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. As shown in Tables 5-25 and 5-26, the average ratio of annualized reporting program costs to receipts of establishments owned by model small enterprises was less than 1% for industries presumed likely to have small businesses covered by the reporting program.

We acknowledge that several enterprise categories have ratios that exceed this threshold (e.g., enterprise with one to 20 employees). The following enterprise categories have sales test results between 1% and 3% for entities with less than 20 employees: Oil and Gas Extraction (211), Pulp & Paper Manufacturing (322), Cement & Other Mineral Production(327), Primary Metal Manufacturing (331), Computer & Electronic Product Manufacturing (334), Electronic equipment, appliance, and component manufacturing (335), Cement (32731), Glass (3272), Lead Production (3314), Lime Manufacturing (327410), Nitric Acid (325311), Phosphoric Acid (325312), Pulp & Paper—Pulp Mills (322110), and Zinc Production (3314).

Below we take a more detailed look at the categories noted above as having sales test ratios above 1%. EPA collected information on the entities likely to be covered by the rule for the hybrid 25,000 ton threshold as part of the expert sub-group process. This can be broken down by a more detailed threshold-based analysis and a more detailed employee-based analysis.

Threshold-based Analysis of Categories Having Sales Test Ratios Above 1%

Cement (32731)

Comparing facility counts in the proposed rule with Census data can be misleading. The Census data almost without exception include a larger number of "establishments" than we know to be manufacturing the product, based on EPA bottom up industry analyses. For example, the 2002 Economic Census suggests that for cement there are 246 establishments, however, according to the Portland Cement Association Plant Information Summaries, there are 107 Portland cement facilities manufacturing cement, and these are the facilities proposed for inclusion in the rule. The differences between the Census and the industry publications may be due to the way in which Census defines an "establishment." For example, one cement facility, as identified by the PCA that crosses several miles, may actually be multiple "establishments" according to Census.

The cement facilities proposed for inclusion in the rule would be the largest facilities as identified by the Census. This can be seen through a comparison of the value of shipments (i.e., the value of cement produced). Greater than 96% of the product is produced by facilities with more than 20 employees. Further, all facilities cross a 25,000 mtCO_2 threshold; all but one exceed a 100,000 mtCO_2 threshold.

Lime (327410)

Data on the number of lime facilities comes from the USGS Directory of Lime Plants in the United States in 2005 (USGS 2006). The Census data identifies fewer lime facilities, likely because of the differences in defining a lime facility. Some facilities produce just lime and they can be easily identified as part of the lime manufacturing industry. However, a number of facilities produced lime as an intermediate product, which is then used as an input to the final product (this also happens in the iron and steel industry and pulp and paper). Lime has very similar characteristics to cement described above, because of similar manufacturing processes.

Glass (3272)

For the glass industry, 55 facilities are above a 25,000 ton CO_2e threshold. All of these facilities are from companies with over 20 employees. All but three facilities are from companies with greater than 100 employees. Data for the glass industry were based on the Glass Factory Directory 2004 (GFD 2004) and EPA's National Emissions Inventory (NEI) 1998 (EPA 2002).

Nitric Acid (325311), Phosphoric Acid (325312), Iron and Steel (331112)

There are 45 nitric acid facilities based on a bottom-up industry database under development by EPA. This dataset shows that all of these facilities are from companies with over 20 employees. All but two facilities are from companies with greater than 100 employees. Similarly, there are 14 phosphoric acid facilities, all of which are from companies with over 20 employees. There are 121 iron and steel facilities that exceed the 25,000 metric ton threshold (130 total) based on the same database. All of these facilities are from companies with over 20 employees. Three facilities have fewer than 500 employees.

Pulp and Paper (322/322110)

The pulp and paper industry encompasses over 5,000 facilities. The thresholds proposed in this proposed rule are expected to include less than 10% of the total industry. The proposed rule would cover about 425 of the most emissions intensive facilities. Considering that emissions may be assumed to be positively correlated to number of employees, it is highly likely that these facilities are all over 100 employees. According to the Census, about 27% of facilities are over 100 employees. According to the preamble all 425 facilities exceed all reviewed thresholds, including 100,000 $mtCO_2$e.

Oil and Gas Extraction (211)

Of the 50 offshore oil and gas platforms, we have information on 32 indicating they are well over the 500 employee small business threshold. For the remaining 18, information is not available; however, we strongly believe that given the investment required and the information available to us, that none of these would be small businesses.

Computer & Electronic Product Manufacturing (334) and Electrical Equipment, Appliance, and Component Manufacturing (335)

For the electronics industry, 94 facilities are above a 25,000 ton CO_2e threshold. The smallest of these companies has, as of February 2007, 88 employees. Considering that emissions may be assumed to be positively correlated to number of employees, it is highly likely that the other facilities that exceed the 25,000 ton CO_2e threshold have over 100 employees. Data for the electronics industry were based on the semiconductor industry's World Fab Watch (2007 edition) and press reports regarding number of employees.

Zinc Production (3314)

For the zinc industry, there are 5 facilities that exceed the 25,000 ton threshold. These facilities are from companies with greater than 500 employees. Data for on the number of zinc facilities and production capacity at these facilities were based on the US Geologic Survey Mineral Yearbook: Annual Zinc Report and other publicly available information from zinc producers.

Employee-based Analysis of Categories Having Sales Test Ratios Above 1%

Two recent studies by the Pew Center on Global Climate Change and the Nicholas Institute for Environmental Policy Solutions at Duke University (Pew, 2002; Nicholas Institute, 2008) show there is a recognized positive correlation between GHG emissions and the number of employees: the largest facilities will have the largest amount of emissions. A number of studies use the number of employees to help quantify emissions. According to these studies, most small manufacturers do not burn sufficient fuel to cross a 10,000 metric ton CO_2e threshold. By the time a facility uses sufficient energy to exceed these types of thresholds, they are large.

According to the Nicholas Institute study, "If the facility has fewer than 50 employees, and no smoke-stack, it will be virtually guaranteed safe passage around any reporting requirement, regardless of what the industry may be. The vast majority of manufacturing industries are not expected to cross a 10,000-ton reporting threshold until the employee count is in the hundreds" (Nicholas Institute, 2008). The final conclusion of this study was that a 10,000 ton threshold for participation would focus on large industry, and would not directly impact the majority of small and medium-sized businesses. Therefore, it is a reasonable assumption that the 25,000 ton CO_2e would include relatively few small entities. This is confirmed by the threshold analysis discussed [above], which found that small production facilities are largely exempt from the rule.

As shown in Table 5-27, the screening analysis suggested several sectors may have 1% to 3% cost-to-receipt ratios for model establishments owned by businesses with less than 20 employees. To assess the likelihood that these small businesses would be covered by the rule, we performed several case studies for manufacturing industries where the cost-to-receipt ratio exceeded 1% (see Table 5-27). For each industry, we used and applied emission data from a recent study examining emission thresholds (Nicholas Institute, 2008). This study provides industry-average CO_2 emission rates (e.g., tons per employee) for the manufacturing industries that correspond to the industries listed in Table 5-22.

Table 5-27. Case Studies of Manufacturing Industries to Determine the Likelihood of Small Businesses Would Be Covered by the Rule

	NAICS Description	SBA Size Standard (effective March 11, 2008)	Average Cost Per Entity ($1,000/entity)	Cost-to Receipt Ratio for an Establishment Owned By an Enterprise with 1 to 20 Employees	Emissions Per Employee (metric tons)	Average Annual Facility Emissions (metric tons)[a]	Emission Data Source: Duke University (2008)
327310	Cement mfg	750	$65	2.1%	1,631	32,620	p.53
3272	Glass & glass product mfg	500 to 1,000	$11	1.7%	258	5,160	p.52
3314	Nonferrous metal (except aluminum) production & processing	750 to 1,000	$23	1.5%	65	1,300	p.57
327410	Lime mfg	500	$60	16.5%	4,124	82,480	p.53
325311	Nitrogenous fertilizer mfg	1,000	$20	1.0%	Facility measure used	2,151	p.48
325312	Phosphatic fertilizer mfg	500	$60	10.1%	Facility measure used	2,200	p.48
322110	Pulp mills	750	$22	1.5%	Facility measure used	1,235	p.39

[a] In cases where an emission rate was reported (tons per employee), we multiplied this rate by 20 employees to estimate annual emissions. In cases where the appropriate emissions rate was not available, we used the reported annual emissions for an establishment with 50 or fewer employees.

As shown in Table 5-27, there are two industries (cement and lime manufacturing) where emission rates suggest small businesses with less than 20 employees could potentially be covered by the rule. As a result, EPA examined in more detail screening analysis using small business information compiled from the latest EPA analyses for these industries (EPA, 2003; RTI, 2008). In these analyses, the cement and lime plants' corporate structures are carefully examined and their ultimate parent companies were identified using industry surveys and the latest private databases such as Dun & Bradstreet. For the Portland cement industry, four ultimate parent companies are classified as small using the SBA firm size standards. The smallest company has one plant and reported revenues of approximately $26 million. Using the average entity cost of $65,000, the cost-sales ratio is less than 1%. For the lime manufacturing industry, 19 ultimate parent companies were classified as small using the SBA firm size standards. The smallest company has one plant and reported revenues of approximately $7 million. Using the average entity cost of $60,000, the cost-sales ratio is also less than 1%.

Additional analysis for a model small government also showed that the annualized reporting program costs were less than 1% of revenue. These impacts are likely representative of ratios in industries where data limitations do not allow EPA to compute sales tests (e.g., general stationary combustion and manure management).

Although this rule would not have a significant economic impact on a substantial number of small entities, the Agency nonetheless tried to reduce the impact of this rule on small entities, including seeking input from a wide range of private- and public-sector stakeholders. When developing the proposed rule, the Agency took special steps to ensure that the burdens imposed on small entities were minimal. The Agency conducted several meetings with industry trade associations to discuss regulatory options and the corresponding burden on industry, such as recordkeeping and reporting. The Agency investigated alternative thresholds and analyzed the marginal costs associated with requiring smaller entities with lower emissions to report. The Agency also recommended a hybrid method for reporting, which provides flexibility to entities and helps minimize reporting costs. A final summary of the emissions covered and the costs imposed by this rule is provided in Table 5-28. As this table indicates, the total national emissions covered under the proposed rule are 3.9 billion MtCO2e, total capital costs for the proposed rule are $87 million, and the national annualized cost for proposed rule in the first year is $160 million.

Table 5-28. Estimated Emissions and Costs by Subpart (2006$)

	Downstream Emissions Estimates (millions of $MtCO_2e$)[a]	% of Total Emissions	Total Capital Costs ($millions)	% of Total Capital Costs	Total First Year Annualized Costs[b] ($millions)	% of Total First Year Costs
Subpart A—General Provisions	0.0	0%	$0.0	0%	$0.0	0%
Subpart B—Electricity Use	0.0	0%	$0.0	0%	$0.0	0%
Subpart C—General Stationary Fuel Combustion Sources	220.0	6%	$12.7	15%	$29.0	18%
Subpart D—Electricity Generation	2,262.0	58%	$0.0	0%	$3.3	2%
Subpart E—Adipic Acid Production	9.3	0%	$0.0	0%	$0.1	0%
Subpart F—Aluminum Production	6.4	0%	$0.0	0%	$0.4	0%
Subpart G—Ammonia Manufacturing	14.5	0%	$0.0	0%	$0.4	0%
Subpart H—Cement Production	86.8	2%	$5.4	6%	$6.9	4%
Subpart I—Electronics Manufacturing	5.7	0%	$0.0	0%	$3.6	2%
Subpart J—Ethanol Production	0.0	0%	$0.3	0%	$0.5	0%
Subpart K—Ferroalloy Production	2.3	0%	$0.0	0%	$0.3	0%
Subpart L—Fluorinated Gas Production	5.3	0%	$0.0	0%	$0.0	0%
Subpart M—Food Processing	0.0	0%	$0.0	0%	$0.6	0%
Subpart N—Glass Production	2.2	0%	$0.0	0%	$0.6	0%
Subpart O—HCFC-22 Production	13.8	0%	$0.0	0%	$0.0	0%
Subpart P—Hydrogen Production	15.0	0%	$0.0	0%	$0.6	0%
Subpart Q—Iron and Steel Production	85.0	2%	$0.0	0%	$18.2	11%
Subpart R—Lead Production	0.8	0%	$0.0	0%	$0.3	0%
Subpart S—Lime Manufacturing	25.4	1%	$4.9	6%	$5.3	3%
Subpart T—Magnesium Production	2.9	0%	$0.0	0%	$0.1	0%
Subpart U—Miscellaneous Uses of Carbonates	0.0	0%	$0.0	0%	$0.0	0%
Subpart V—Nitric Acid Production	17.7	0%	$0.2	0%	$0.9	1%
Subpart W—Oil and Natural Gas Systems	129.9	3%	$37.8	43%	$32.5	20%
Subpart X—Petrochemical Production	54.8	1%	$0.0	0%	$1.6	1%
Subpart Y—Petroleum Refineries	204.7	5%	$1.6	2%	$3.7	2%
Subpart Z—Phosphoric Acid Production	3.8	0%	$0.8	1%	$0.8	1%

(continued)

Table 5-28. Estimated Emissions and Costs by Subpart ($2006) (continued)

	Downstream Emissions Estimates (millions of $MtCO_2e$)[a]	% of Total Emissions	Total Capital Costs ($millions)	% of Total Capital Costs	Total First Year Annualized Costs[b] ($millions)	% of Total First Year Costs
Subpart AA—Pulp and Paper Manufacturing	57.7	1%	$14.8	17%	$9.2	6%
Subpart BB—Silicon Carbide Production	0.1	0%	$0.0	0%	$0.0	0%
Subpart CC—Soda Ash Manufacturing	3.1	0%	$0.0	0%	$0.0	0%
Subpart DD—Sulfur Hexafluoride (SF^6) from Electric Power Systems	10.3	0%	$0.0	0%	$0.4	0%
Subpart EE—Titanium Dioxide Production	3.7	0%	$0.0	0%	$0.1	0%
Subpart FF—Underground Coal Mines	33.5	1%	$0.6	1%	$2.3	1%
Subpart GG—Zinc Production	0.8	0%	$0.0	0%	$0.1	0%
Subpart HH—Landfills	91.1	2%	$7.9	9%	$15.3	10%
Subpart II—Wastewater	0.0	0%	$0.0	0%	$0.0	0%
Subpart JJ—Manure Management	1.5	0%	$0.0	0%	$0.2	0%
Subpart KK—Suppliers of Coal and Coal-based Products & Subpart LL—Suppliers of Coal-based Liquid Fuels		0%	$0.0	0%	$11.0	7%
Subpart MM—Suppliers of Petroleum Products		0%	$0.0	0%	$2.0	1%
Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids		0%	$0.0	0%	$2.1	1%
Subpart OO—Suppliers of Industrial Greenhouse Gases	464.1	12%	$0.0	0%	$0.4	0%
Subpart PP—Suppliers of Carbon Dioxide (CO_2)		0%	$0.0	0%	$0.0	0%
Subpart QQ—Motor Vehicle and Engine Manufacturers	35.4	1%	$0.0	0%	$7.4	5%
Total	**3,869.9**	**100%**	**$87.1**	**100%**	**$160.4**	**100%**

[a]Emissions from upstream facilities are excluded from these estimates to avoid double counting.

[b]Capital Costs annualized using appropriate equipment lifetime and interest rate (see additional details in RIA Section 4).

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SECTION 6
BENEFITS REVIEW

6.1 Synopsis

The proposed reporting rule will collect and verify emissions data from facilities and make the information publicly available. This section reviews the benefits of mandatory reporting programs based on previous experience with emissions inventory programs in the United States and abroad.

Recent policy discussions have highlighted potential benefits to society of the mandatory GHG reporting program (Pew, 2008). Benefits to the public include building public confidence through clear and transparent emission measures and reports and the ability of the public to make facilities accountable for their emissions. A GHG reporting system will also have the benefit of providing policy makers and analysts with a data set that is comprehensive and reduces the potential for policy bias due to non-reporting by certain sectors.[17] Benefits to industry include the identification of cost-effective GHG reduction opportunities and disclosure that provides firms with incentives to reduce emissions voluntarily, and provides emissions data to service industries, such as insurance and financial markets. Availability of emissions information to the public, consumers, investors, corporations and government regulators provides a sound basis for future policy analysis. This benefits society as a whole. Accurate and transparent information is necessary for the implementation of efficient approaches that meet environmental goals with the lowest cost to the economy.

6.2 Background

6.2.1 Background on Existing GHG Reporting Rules

Currently, there are a variety of reporting programs in the United States. The U.S. Acid Rain Program requires electricity-generating units that are regulated for SO_2 to also report CO_2 emissions. In addition, there are a variety of mandatory state-level programs in 12 states, such as Maine, New Jersey, Connecticut, California, New Mexico, Nevada, and Oregon. A number of voluntary corporate-level systems exist as well, including Climate Leaders, the California Climate Action Registry, and 1605(b) program. These programs were designed for many different purposes and are not harmonized. These efforts also may not provide a sufficient basis for future GHG reduction policies, because their systems do not provide a comprehensive and coherent picture of all GHG emission sources at the facility level. The majority of emissions in

[17] The rule has broad coverage of GHG emitting sectors, but does exclude sectors such as international bunker fuels, enteric fermentation, wastewater treatment, among other smaller sources and sinks.

the United States are not tracked under these systems. The proposed federal mandatory reporting system would build upon these efforts and provide policy makers with data to inform future national climate policies.

6.2.2 Benefits Analysis Methodology

This section describes the benefits of a mandatory reporting system. Because quantifying the benefits of a policy that monitors but does not reduce GHG emissions would be very difficult, the benefits laid out in this chapter are strictly qualitative. This qualitative review is based on a systematic literature review of previous mandatory reporting systems, voluntary reporting systems, and a sampling of emissions reduction policies with and without mandatory reporting. Ideally, empirical estimates of the accrued benefits from access to information based on pollution registries would be used to estimate the benefits of the greenhouse gas registry. While the academic literature provides robust estimates for the benefits of policies which reduce pollution directly, it provides little empirical data of the benefits of reporting emissions data. Benefit studies of environmental information disclosure focus primarily on the structure or rationale for examining the benefits of information disclosure (Beierle, 2003). Therefore, this study focuses on a qualitative review of the benefits of a greenhouse gas reporting policy.

The purpose of this qualitative literature review is to relate the ongoing policy dialogue about reporting systems and past policies to the proposed mandatory GHG reporting rule. This literature reviews current air pollution and toxic emission reporting rules and their outcomes on stakeholders, while acknowledging that the differences between air pollution and toxics compare to greenhouse gases are significant.[18] The following is a description of all benefits discussed in the academic literature of a pollution reporting rule.

6.3 Discussion of Benefits

6.3.1 Benefits of a Mandatory Program

A mandatory GHG emissions reporting system would enable the creation of a comprehensive, accessible database. Such a database would yield benefits to society in myriad ways by lowering the information costs associated with emission reductions. Both the Organization for Economic Co-Operation and Development (OECD) (2005) and the EPA (2003) have documented ways in which the public, industry, government, investment community and academic community have utilized pollutant release and transfer registers (PRTRs) to accomplish tasks that would be costly or unattainable without such available information. Below,

[18] See World Bank (2000) for a discussion of the main advantages and disadvantages of using information disclosure as a policy tool generally.

the benefits of uses relevant to a GHG emissions reporting system are explored qualitatively for the respective stakeholder groups.

6.3.2 Benefits to the Public

6.3.2.1 Policy Development

The greatest benefit of mandatory reporting of industry GHG emissions to government would be realized in developing future GHG policies. For example, in the European Union's Emissions Trading Scheme (ETS), a lack of accurate monitoring at the facility level before establishing CO_2 allowance permits resulted in allocation of permits for emissions levels an average of 15% above actual levels in every country except the United Kingdom. Consequently, the allowance market experienced a price drop when the first year of emissions data were published (Bailey, 2007). The U.S. mandatory reporting rule would creates a foundation of reliable baseline emission estimates for the purpose of informing future policies and avoiding unexpected consequences of those policies.

6.3.2.2 Builds Public Confidence and Trust

A mandatory reporting system will increase transparency of facility emissions data. A qualitative study in the United Kingdom compared similar communities surrounding chemical complexes with and without right-to-know laws, and found that the community with the right-to-know law and corresponding available data on toxic emissions experienced increased levels of trust towards government and industry to ensure the environmental protection and public health. (Gouldson, 2004). While greenhouse gases do not directly affect health, increased environmental stewardship is becoming a higher priority among Americans (PEW, 2007). Public confidence in the government and industries actions to reduce greenhouse gas emissions is expected to increase with a transparent accounting of GHG emissions.

6.3.2.3 Direct Actions

Transparent, public data on emissions allows for accountability of polluters to the public stakeholders who bear the cost of the pollution. Citizens, community groups and labor unions have made use of data from PRTRs to negotiate directly with polluters to lower emissions, circumventing greater government regulation. There are several examples in the literature of environmental organizations and community groups negotiating with facilities directly based on their publicly available pollution data (EPA, 2003). While many of these groups were local, grassroots organizations, focused geographically on environmental health issues, it is likely that environmental organizations focused on climate change will use the data in a similar manner.

The Mandatory Reporting Rule for GHG emissions would allow groups interested in pressuring industry to reduce their emissions to negotiate with the top emitters.

6.3.2.4 Voluntary Programs

Voluntary agreements to promote energy efficiency in industry or promote specific types of technologies are used widely in the industrial sector. The U.S. government currently has several ongoing voluntary programs to help reduce GHGs including, the Voluntary Aluminum Industrial Partnership to reduce perfluorocarbon (PFC) emissions, and the Landfill Methane Outreach Program, the Coal Mine Methane Outreach Program, Natural GasStar and AgStar which promote the capture-and-use of methane in these sectors. In addition, some industries have voluntary plans or roadmaps to help the industry achieve an emissions reduction goal. The American Iron and Steel Institute introduced an energy efficiency goal and a research and development plan for the industry.

While no study has been done on whether or not voluntary programs with mandatory reporting are more effective than those without, evaluations of several major voluntary programs have noted that need for a strong reporting mechanism is necessary (Worrell and Price, 2001). A transparent reporting system increases the credibility of the voluntary program and the reductions attributed to the program. A standardized reporting system also allows program mangers to readjust the programs strategy to meet the evolving needs of a program. In the case of the GHG reporting rule, the data collected would help evaluate the achievements of the current programs and provide verification of voluntary actions by industry, strengthening the effectiveness of the programs.

6.3.2.5 Consumers of GHG-Intensive Goods and Labeling

Publicly available emissions data would allow individuals to alter their consumption habits based on the GHG emissions of producers. Green labeling programs may use the verified GHG emissions data from this mandatory rule to provide comprehensive information to the public, particularly on durable goods such as appliances, electronics, etc. However, as with all eco-labeling projects, the process takes a committed effort to build recognition and market products as having a low carbon footprint.[19] Uncertainty over the willingness to pay for low carbon products makes this benefit to consumers difficult to predict.

[19] For a thorough review of evaluations conducted for eco-labeling programs, see Thogerson, 2002.

6.3.3 Benefits to Industry and Investors

6.3.3.1 Public Relations

One benefit of GHG emissions monitoring for industry is the value of having independent, verifiable data to present to the public to demonstrate appropriate environmental stewardship. For example, General Motors issues its *Corporate Responsibility and Sustainability Report*, which makes use of TRI data and the Canadian National Pollutant Release Inventory to support its environmental achievements. Such monitoring also allows for inclusion of standardized GHG data into environmental management systems (EMS), providing the necessary information to achieve and disseminate their environmental achievements. Using data from a verified, standard methodology as proposed under the GHG reporting rule gives the facilities credibility when claiming environmental improvements. Hamilton (1995) and Konar and Cohen (1997) are two examples of empirical studies that have investigated how the TRI has affected firm behavior and stock market valuation. Hamilton (1995) finds a stock price return of -0.03% due to TRI release. Firms that experienced the largest drop in their stock prices also reacted by reducing their reported emissions most in subsequent years.

6.3.3.2 Standardization

Once facilities invest in the institutional knowledge and systems to report emissions, the cost of monitoring should fall and the accuracy of the accounting should improve. A standardized reporting program will also allow for facilities to benchmark themselves against similar facilities to understand better their relative standing within their industry.

6.3.3.3 Potential Cost Savings

Mandatory reporting of GHG emissions could illuminate previously unmeasured wasteful processes, yielding cost-saving conservation measures that would offset some of the costs associated with the monitoring. Acushnet Rubber Company, Inc. saves approximately $100,000 annually after eliminating use of the potential carcinogen trichloroethylene, identified using TRI, from its facility as part of its EMS (EPA, 2007). Under a mandatory reporting rule for GHG emissions, facilities may discover their facilities could feasibly install cost saving, emission reduction technologies such as energy efficiency improvements, co-generation opportunities, or methane capture-and-use technologies.

6.3.3.4 Data Valuable to Service Industries

In addition to the benefits for the facilities being monitored, the data can be valuable to companies doing business with GHG-emitting firms. Firms have sold pollution-prevention technologies to customers found using TRI data (Pew, 2008). In addition, insurance companies may find these data valuable in assessing risk. In general, improved information lowers search and transaction costs for providers of mitigation products and services.

6.3.4 Reducing Uncertainty: Benefits to all Stakeholders

Reducing uncertainty in greenhouse gas emission estimates is an underlying benefit that increases benefits to all stakeholders. Policy development, direct action by the public and consumers, standardization, and reliable data for firms, shareholders and service industries to use in decision-making all require certainty in emission estimates in order to make environmentally sound and cost-effective decisions. Increased certainty in the emission estimates facilitates the comparison across reduction options, companies and sectors where different data or approaches have been used. Some emission sources covered under this rule are more uncertain than others because of the nature of the greenhouse gas generation (biological vs. chemical reaction) and the lack of basic data collection (i.e., the amount and content of waste being disposed at each landfill). Finalizing this rule will increase the certainty of these emissions due to increased information about each source and may spur additional research into sources that are not as well understood or documented. (IIASA, 2007)

In addition, increased certainty in emission estimates increase the probability that commitments to reductions have been credibly met. This allows for a stable emissions trading market, whether voluntary or mandatory, and reinforces the credibility of an emissions credit. Without increased certainty within a sector, company or a specific project, the emission credit produced may be considered risky and not trade for full value. Increasing the certainty of each credit benefits the buyer, the seller, and the overall market place. (PWC, 2007)

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SECTION 7
STATUTORY AND EXECUTIVE ORDER REVIEWS

This section describes EPA's compliance with several applicable executive orders and statutes during the development of the proposed mandatory GHG reporting rule.

7.1 Executive Order 12866: Regulatory Planning and Review

Under Section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual economic effect of $100 million or more. EPA's cost analysis, presented in Section 4, estimates that under the proposed regulatory option, the total annualized cost of the proposed rule will be approximately $168 million during the first year of the program and $134 million in subsequent years (including $8 million of programmatic costs to the Agency). Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866, and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, EPA prepared this RIA, an analysis of the potential costs and benefits associated with this action. In this report, EPA has identified the regulatory options considered, their costs, the emissions that would likely be reported under each option, and explained the selection of the option chosen for the proposed rule. The costs of the proposed rule are reported in Section 4. In addition, EPA has conducted a qualitative assessment of the benefits of the proposed rule, which are reported in Section 6. Overall, EPA has concluded that the costs of the proposed mandatory GHG reporting rule, while substantial, are outweighed by the potential benefits of more comprehensive information about GHG emissions.

7.2 Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The ICR document prepared by EPA has been assigned EPA ICR number 2300.01.

EPA plans to collect complete and accurate economy-wide data on facility-level GHG emissions. Accurate and timely information on GHG emissions is essential for informing future climate change policy decisions. Through data collected under this rule, EPA will gain a better understanding of the relative emissions of specific industries, and the distribution of emissions from individual facilities within those industries. The facility-specific data will also improve our understanding of the factors that influence GHG emission rates and the actions that facilities are already taking to reduce emissions. Additionally, EPA will be able to track the trend of emissions from industries and facilities within industries over time, particularly in response to policies and potential regulations. The data collected by this rule will improve EPA's ability to formulate climate change policy options and to assess which industries would be affected, and how these industries would be affected by the options.

This information collection is mandatory and will be carried out under CAA Sections 114 and 208. Information identified and marked as Confidential Business Information (CBI) will not be disclosed except in accordance with procedures set forth in 40 CFR Part 2. However, emissions information collected under CAA Sections 114 and 208 cannot be claimed as CBI and will be made public.

The projected cost and hour burden is $143 million and 1.63 million hours per year. The estimated average burden per response is 2 hours; the proposed frequency of response is annual for all respondents that must comply with the proposed rule's reporting requirements, except for electricity-generating units that are already required to report quarterly under 40 CFR Part 75 (ARP); and the estimated average number of likely respondents per year, excluding 43 federal facilities, is 18,775. The cost burden to respondents resulting from the collection of information includes the total capital and start-up cost annualized over the equipment's expected useful life (averaging $20.7 million per year) a total operation and maintenance component (averaging $22.4 million per year), and a labor cost component (averaging $100.0 million per year). Burden is defined at 5 CFR Part 1320.3(b). These cost numbers differ from those shown elsewhere in the RIA for several reasons:

- ICR costs represent the average cost over the first three years of the rule, but costs are reported elsewhere in the RIA for the first year of the rule and for subsequent years of the rule.;
- The costs of reporting electricity purchases have been excluded from the ICR, but are still reported in the RIA, although electricity use reporting has been removed from the proposed rule and EPA is soliciting comment on it (see Section 4.2.2, pg 4-18); and
- The first-year costs of coverage determination, estimated to be $867.60 per facility for approximately 16,800 facilities that ultimately determine they do not have to report, are included in the ICR but not in the RIA (see Section 4.2.2, pg 4-18). These costs, averaged over 3 years, are $4.87 million incurred by an average of 5,613 respondents per year.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR Part 9. To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, EPA has established a public docket for this rule.

7.3 Regulatory Flexibility Act

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

For the purposes of assessing the impacts of the proposed rule on small entities, we defined a small entity as (1) a small business, as defined by SBA's regulations at 13 CFR Part 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

For affected small entities, EPA conducted a screening assessment comparing compliance costs for affected industry sectors to industry-specific receipts data for establishments owned by small businesses. This ratio constitutes a "sales" test that computes the per-entity annualized compliance costs of this proposed rule as a percentage of sales and determines whether the ratio exceeds some level (e.g., 1% or 3%).[20] The cost-to-sales ratios were constructed at the establishment level (average reporting program costs per establishment/average establishment receipts) for several business size ranges. This allowed EPA to account for receipt differences between establishments owned by large and small businesses and differences in small business definitions across affected industries. EPA used average per-entity annualized costs for each industry sector, which tends to overstate costs incurred by the smallest entities. The results of the screening assessment are reported in Section 5 (Tables 5-26 and 5-27). The cost-to-sales ratios are less than 1% for establishments owned by small businesses that EPA considers most likely to be covered by the reporting program (e.g., establishments owned by businesses with 20 or more employees). The screening analysis thus indicates that the proposed rule will not have a significant economic impact on a substantial number of small entities. The screening assessment for small governments compared the sum of

[20] EPA's Regulatory Flexibility Act (RFA) guidance for rule writers suggests the "sales" test continues to be the preferred quantitative metric for economic impact screening analysis.

average costs of compliance for combustion, local distribution companies, and landfills to average revenues for small governments. Even for a small government owning all three source types, the costs constitute less than 1 percent of average revenues for the smallest category of governments (those with fewer than 10,000 people).

For several source categories, enterprises with fewer than 20 employees have cost-to-sales ratios between 1% and 3%. EPA examined these in greater detail, and concluded that very few firms with fewer than 20 employees would be subject to the rule. Although this proposed rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless took several steps to reduce the impact of this rule on small entities. For example, EPA determined appropriate thresholds that reduce the number of small businesses reporting. In addition, EPA is not requiring facilities to install CEMS if they do not already have them. Facilities without CEMS can calculate emissions using readily available data or data that is less expensive to collect, such as process data or material consumption data. For some source categories, EPA developed tiered methods that are simpler and less burdensome. Also, EPA is requiring annual reporting instead of more frequent reporting.

Through comprehensive outreach activities, EPA held approximately 100 meetings and/or conference calls with representatives of the primary audience groups, including numerous trade associations and industries that include small business members. EPA's outreach activities are documented in the memorandum, "Summary of EPA Outreach Activities for Developing the Greenhouse Gas Reporting Rule," located in Docket No. EPA-HQ-OAR-2008-0508-055.

7.4 Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), P.L. 104-4, establishes requirements for federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. Under Section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "federal mandates" that may result in expenditures to state, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, Section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of Section 205 do not apply when they are inconsistent with applicable law. Moreover, Section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes, with the final rule, an explanation of why that alternative is not being adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must develop a small government agency plan under Section 203 of the UMRA. The plan must provide for notifying potentially affected small governments; enabling officials of affected small governments to have meaningful and timely input in developing EPA regulatory proposals with significant federal intergovernmental mandates; and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that this rule contains a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. Accordingly, EPA has prepared, under Section 202 of the UMRA, a written statement that is presented below. The statement addresses the following items:

1. The authorizing legislation (7.4.1).
2. Benefit-cost analysis, including an analysis of the distribution of costs among ownership types, sectors of the economy, and regions of the country; and an assessment of the extent to which the costs of state, local, and tribal governments could be paid for by the federal government (Section 4.1, Section 5, and Section 7.4.2).
3. Estimates of future compliance costs and disproportionate budgetary effects (Section 4.1, 7.4.3).
4. Macroeconomic impacts (Section 7.4.4).
5. A summary of EPA's consultation with state, local, and tribal governments and their concerns, including a summary of the Agency's evaluation of those comments and concerns (Section 2.3.4, Section 7.4.5).
6. Identification and consideration of regulatory alternatives and the selection of the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule (Section 4.4, Section 7.4.6).

7.4.1 Authorizing Legislation

On December 26, 2007, President Bush signed the FY2008 Consolidated Appropriations Amendment, which authorized funding for the U.S. Environmental Protection Agency (EPA) to develop and publish a draft rule on an accelerated schedule:

> [N]ot less than $3,500,000 shall be provided for activities to develop and publish a draft rule not later than 9 months after the date of enactment of this Act, and a final rule not later than 18 months after the date of enactment of this Act, to

> require mandatory reporting of GHG emissions above appropriate threshold in all sectors of the economy.

The accompanying explanatory statement stated that EPA shall "use its existing authority under the Clean Air Act" to develop a mandatory GHG reporting rule.

> The agency is further directed to include in its rule reporting of emission resulting from upstream production and downstream sources, to the extent that the Administrator deems it appropriate. The Administrator shall determine appropriate thresholds of emissions above which reporting is required, and how frequently reports shall be submitted to EPA. The Administrator shall have discretion to use existing reporting requirements for electric generating units under Section 821 of the Clean Air Act.

EPA has developed this regulation under authority of Sections 114 and 208 of the Clean Air Act. The required activities under this federal mandate include monitoring, recordkeeping, and reporting of GHGs.

7.4.2 Benefit-Cost Analysis

EPA has considered the costs and benefits of the proposed GHG reporting rule. The engineering costs of the rule for both stationary sources and mobile sources are described in Section 4. Costs for stationary sources are estimated to be approximately $153 million in the first year; for subsequent years, costs for stationary sources are estimated to be approximately $120 million. For mobile sources, the costs are estimated to be approximately $7 million for the first year and for subsequent years.

7.4.2.1 Distribution of Costs

Costs were estimated for each of the subparts of the rule, which include stationary combustion, electricity generation, various industrial processes and biological processes, as well as mobile sources. Among the various subparts of the rule, most affect only privately owned sources. The exceptions are stationary combustion, landfills, electricity generators, and natural gas suppliers, or local distribution companies (LDCs).

Table 7-1 presents the distribution of ownership (private owners and state, local, and tribal government owners) for the sectors that include both privately owned and publicly owned facilities.

Table 7-1. Estimated Private and Government Costs in Selected Sectors (10^3 \$2006)

Public/Private Respondent Breakdown	Landfills	Stationary Combustion	Electricity Generation	LDCs
Costs of private respondents	$4,436	$22,527	$2,813	$298
Costs of state/local/tribal government (SLTG) respondents	$7,247	$3,817	$398	$753
Costs of federal respondents (fed owned/operated)	$127	$0	$53	$0
Total costs by sector	$11,990	$26,344	$3,264	$1,050

Note: Columns may not sum to totals due to rounding.

This regulation applies directly to both public- and private-sector facilities that directly emit GHGs and to those that supply fuel or chemicals that emit GHGs when used. However, this rule does not impose any implementation responsibilities on state, local, or tribal governments, and it is not expected to increase the cost of existing regulatory programs managed by those governments. The proposed rule imposes burdens on state, local, or tribal governments only when they own affected facilities that must comply with the proposed rule. Overall, EPA estimates that approximately 2,600 facilities owned by state, local, or tribal governments will be required to report their greenhouse gas emissions by the proposed rule. EPA estimates that an additional 1,979 facilities owned by state, local, or tribal governments will incur some costs during the first year of the rule to make a reporting determination and subsequently determine that their emissions are below the threshold and thus, they are not required to report their emissions. EPA does not anticipate that substantial numbers of either public- or private-sector entities will incur significant economic impacts as a result of this proposed rule making. Overall, EPA estimates that for most sectors, the costs represent at most 0.1% of sales or receipts. Even for small entities, EPA estimates that the costs are on average less than 0.5% of sales or receipts. The impacts associated with such costs are not generally considered significant. UMRA requires an analysis of possible federal assistance to state, local, or tribal governments affected by the proposed rule. Because the rule imposes no implementation or regulatory responsibilities and only imposes compliance costs on government-owned GHG emitting facilities, EPA is unaware of any federal assistance available to these governments to subsidize their compliance costs.

In addition to examining the distribution of ownership between private entities and governments for these sectors, EPA also examined the distribution of respondents and costs across industry sectors. Table 7-2 shows the distribution of costs for the first year after promulgation and for subsequent years for subparts with the highest costs for the 25,000 MT threshold. Of the $168 million in costs estimated for the first year of the regulation, oil and natural gas transportation account for nearly 20% of national costs. Iron and steel production and general stationary combustion are each between 10% and 20% of national first-year costs.

Table 7-2. National Cost Estimates by Sector: Recommended Option ($million)

Sector	First Year $	First Year Share	Subsequent Years $	Subsequent Years Share
Subpart A—General Provisions				
Subpart B—Electricity Use				
Subpart C—General Stationary Fuel Combustion Sources	$29.0	17%	$24.4	18%
Subpart D—Electricity Generation	$3.3	2%	$3.3	2%
Subpart H—Cement Production	$6.9	4%	$4.3	3%
Subpart I—Electronics Manufacturing	$3.6	2%	$3.6	3%
Subpart Q—Iron and Steel Production	$18.2	11%	$14.1	11%
Subpart S—Lime Manufacturing	$5.3	3%	$3.0	2%
Subpart W—Oil and Natural Gas Systems	$32.5	19%	$28.1	21%
Subpart Y—Petroleum Refineries	$3.7	2%	$2.8	2%
Subpart AA—Pulp and Paper Manufacturing	$9.2	5%	$9.0	7%
Subpart FF—Underground Coal Mines	$2.3	1%	$2.3	2%
Subpart HH—Landfills	$15.3	9%	$10.4	8%
Subpart KK—Suppliers of Coal and Coal-based Products and Subpart LL—Suppliers of Coal-based Liquid Fuels	$11.0	7%	$5.4	4%
Subpart MM—Suppliers of Petroleum Products	$2.0	1%	$0.8	1%
Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids	$2.1	1%	$1.3	1%
Subpart QQ—Motor Vehicle and Engine Manufacturers	$7.4	4%	$7.4	6%
Private Sector, Total	$160.4	95%	$127.0	95%
Public Sector, Total	$8.0	5%	$7.0	5%
Total	$168.4	100%	$134.0	100%

Note: An additional $3.5 million is incurred annually by the public sector during the rulemaking process, which will last between 1 and 2 years.

Landfills, pulp and paper manufacturing, and suppliers of coal-based products each represent between 5% and 10% of national costs. All other sectors account for less than 5% of national costs. In subsequent years, the overall distribution is similar, although the costs and shares of general stationary combustion and oil and natural gas systems' shares increase slightly, while other subparts' shares fall somewhat.

EPA does not have sufficient information to characterize the regional distribution of affected sources.

7.4.2.2 Characterization of Benefits of Mandatory Reporting Programs

EPA also examined the benefits of the proposed rule through a qualitative benefits assessment. EPA conducted a literature review to identify and characterize the benefits of programs that require mandatory reporting of environmental information. These programs convey benefits to the public, to investors, to industry, and to government. The benefits, described in Section 6 of this document, include improved information about GHG emissions that would enhance America's ability to develop sound future climate policies and that may encourage GHG emitters to develop voluntary plans to reduce their emissions. Although EPA was unable to quantify or value these benefits, they may be substantial.

7.4.3 Future Costs and Disproportionate Budget Effects

Although EPA acknowledges that, over time, changes in the patterns of economic activity may mean that GHG generation, and thus reporting costs, will change, data are inadequate for projecting these changes. Thus, EPA assumes that costs averaged over the first three years are typical of ongoing costs of compliance. EPA estimates that future compliance costs, including approximately $8.0 million in federal programmatic costs, will total approximately $145 million per year. These costs are broadly distributed to a variety of economic sectors and represent less than 0.1% of revenues for most affected sectors. Thus, EPA does not believe that the costs are large enough, in general, to impose disproportionate budgetary effects.

7.4.4 Impacts on the National Economy

EPA estimates that future compliance costs (based on average costs over the first 3 years) will total approximately $145 million per year. These costs are broadly distributed to a variety of economic sectors and represent approximately 0.001% of 2007 gross domestic product; overall, EPA does not believe the proposed rule will have a significant macroeconomic impact on the national economy.

7.4.5 Consultation with State, Local, and Tribal Governments

Consistent with the intergovernmental consultation provisions of Section 204 of the UMRA and Executive Order 12875, "Enhancing the Intergovernmental Partnership," EPA initiated an outreach effort with the governmental entities affected by this rule, including state, local, and tribal officials. The outreach audience included state environmental protection agencies, regional and tribal air pollution control agencies, and other state and local government organizations. EPA contacted several states and state and regional organizations already involved in GHG emissions reporting. EPA also conducted several conference calls with tribal organizations. For example, EPA staff solicited input and maintained an open door policy for those interested in discussing the rulemaking. Since January 2008, EPA staff have held more than 100 meetings with stakeholders, including the following:

- trade associations and firms in potentially affected industries/sectors;
- state, local, and tribal environmental control agencies and regional air quality planning organizations;
- state and regional organizations already involved in GHG emissions reporting, such as TCR, CARB, and WCI;
- other federal agencies, such as the U.S. Department of Energy and U.S. Department of Agriculture, which operate reporting systems relevant to GHG emissions; and
- environmental groups and other nongovernmental organizations.

During the meetings, we shared information about the statutory requirements and timetable for developing a rule. Stakeholders were encouraged to provide input on key issues. Examples of topics discussed included existing GHG monitoring and reporting programs and lessons learned, thresholds and schedules for reporting, scope of reporting, handling of confidential data, data verification, and the role of states in administering the program. As needed, the EPA technical workgroups followed up with these stakeholder groups on a variety of methodological, technical, and policy issues. EPA staff also provided information to tribes through conference calls with different Indian tribal working groups and organizations at EPA and through individual calls with tribal board members of TCR.

A full list of organizations EPA met with when developing this proposal has been placed in the docket for this rulemaking (EPA-HQ-OAR-2008-0508-055).

7.4.6 Consideration of Regulatory Alternatives

EPA carefully examined regulatory alternatives and selected the lowest cost/least burdensome alternative deemed by EPA to be adequate to address congressional concerns and to provide a comprehensive source of information about emissions of GHGs. Section 3 discusses the recommended option. The evaluation of the proposed alternative and the other alternatives considered is described in Section 4.

As described above, EPA evaluated a variety of options for each dimension of the proposed GHG reporting program, and selected a preferred or recommended option for each dimension.

7.4.6.1 Recommended Options

We summarize the recommended option for each dimension below.

- **Threshold:** Hybrid approach
  - A facility that emits 25,000 tons CO_2e/year or more reports all sources for which there are methods.
  - The thresholds fall generally into three groups: capacity, emissions, or entire source category (“All in”).
  - EPA may allow a facility to use a capacity threshold when already reporting (e.g., ARP) or where an emissions-based threshold is not practical (e.g., landfills).
- **Measurement Methodology:** Hybrid approach, with source-specific methodologies
  - A facility must use direct measurement of stationary combustion sources where CEMS are currently installed (with some exceptions), including for other regulatory programs (e.g., CO_2 emissions from EGUs in ARP).
  - A facility must use source-specific calculation methods for other sources at the facility.
- **Reporting Frequency:** Annual
  - All reporters should report their emissions annually.
  - An exception exists for those already reporting quarterly for existing mandatory programs (e.g., ARP, MSHA, EIA).
- **Verification:** EPA as the verifier
  - A facility should report emissions data and supporting information directly to EPA; EPA will use the information to verify the data.

7.4.6.2 Scenarios Evaluated

EPA developed alternative reporting scenarios and assessed the costs and emissions associated with each. Alternative scenarios were developed by creating the recommended scenario (the recommended option for each dimension, as shown in Table 3-1), then varying the levels in one dimension while keeping the other three dimensions at the recommended options. The alternative reporting scenarios evaluated are listed below:

1. A 1,000 tCO_2e threshold; recommended options for methodology, frequency, and verifier.

2. A 10,000 tCO_2e threshold; recommended options for methodology, frequency, and verifier.
3. A 100,000 tCO_2e threshold; recommended options for methodology, frequency, and verifier.
4. The measurement variable is changed to direct measurement; recommended option for threshold, frequency, and verifier.
5. The measurement variable is changed to default emissions factors; recommended option for threshold, frequency, and verifier.
6. Existing federal data used for measurement of fuel suppliers; recommended option for threshold, frequency, verifier, and methodology for other sources.
7. EPA uses default carbon content for fuel suppliers; recommended option for threshold, frequency, verifier, and methodology for other sources.
8. Reporting is quarterly; recommended option for threshold, methodology, and verifier.
9. Verification is done by a third party; recommended option for threshold, methodology, and frequency.
10. Reporting from upstream sources only; recommended option for methodology, frequency, and verifier.

Although some of the alternatives considered may result in lower costs, EPA believes that the recommended option is the lowest-cost option available that would provide adequate information on GHG emissions to inform future policy making.

7.5 Executive Order 13132: Federalism

Executive Order 13132, entitled “Federalism” (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure “meaningful and timely input by state and local officials in the development of regulatory policies that have federalism implications.” “Policies that have federalism implications” is defined in the executive order to include regulations that have “substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.”

This proposed rule does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132.

This regulation applies to public- or private-sector facilities that directly emit GHGs and to those that supply fuel or chemicals that emit GHGs when used. Relatively few government facilities would be affected. This regulation also does not limit the power of states or localities to collect GHG data and/or regulate GHG emissions. Thus, Executive Order 13132 does not apply to this rule.

7.6 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Executive Order 13175, entitled "Consultation and Coordination with Indian Tribal Governments" (59 FR 22951, November 6, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications."

This proposed rule is not expected to have tribal implications, as specified in Executive Order 13175. This regulation applies to facilities that directly emit GHGs and to those that supply fuel or chemicals that emit GHG when used. Few facilities expected to be affected by the proposed rule are likely to be owned by tribal governments. Thus, Executive Order 13175 does not apply to this proposed rule.

Although Executive Order 13175 does not apply to this proposed rule, EPA sought opportunities to provide information to tribal governments and representatives during development of the rule. In consultation with EPA's American Indian Environment Office, EPA's outreach plan included tribes. EPA staff provided information to tribes through conference calls with multiple Indian working groups and organizations at EPA that interact with tribes and through individual calls with two tribal board members of TCR. In addition, EPA prepared a short article on the GHG reporting rule that appeared on the front page of a tribal newsletter—*Tribal Air News*—that was distributed to EPA/OAQPS's network of tribal organizations. EPA gave a presentation on various climate efforts, including the mandatory reporting rule, at the National Tribal Conference on Environmental Management in June, 2008. In addition, EPA had copies of a short information sheet distributed at a meeting of the National Tribal Caucus. For a complete list of tribal contacts, see the "Summary of EPA Outreach Activities for Developing the Greenhouse Gas Reporting Rule," in the Docket for this rulemaking (EPA-HQ-OAR-2008-0508-055).

7.7 Executive Order 13045: Protection of Children from Environmental Health and Safety Risks

EPA interprets Executive Order 13045 (62 F.R. 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under Section 5-501 of the executive order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it does not establish an environmental standard intended to mitigate health or safety risks.

7.8 Executive Order 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use

This proposed rule is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, we have concluded that this rule is not likely to have any adverse energy effects.

This proposal relates to monitoring, reporting, and recordkeeping at facilities that directly emit GHGs and to those that supply fuel or chemicals that emit GHGs when used; it does not impact energy supply, distribution or use. Therefore, we conclude that this rule is not likely to have any adverse effects on energy supply, distribution, or use.

7.9 National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law No. 104-113 (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, with explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This proposed rulemaking involves technical standards. EPA proposes to use more than 40 voluntary consensus standards from six different voluntary consensus standards bodies: American Society for Testing and Material (ASTM), American Society of Mechanical Engineers (ASME), International Organization for Standardization (ISO), Gas Processors Association (GPA), American Gas Association (AGA), and American Petroleum Institute (API). These voluntary consensus standards will help facilities monitor, report, and keep records of GHG emissions. No new test methods were developed for this proposed rule. Instead, from existing rules for source categories and voluntary GHG programs, EPA identified existing means of monitoring, reporting, and keeping records of GHG emissions The existing methods (voluntary consensus standards) include a broad range of measurement techniques, including many for combustion sources, such as methods to analyze fuel and measure its heating value, methods to measure gas or liquid flow, and methods to gauge and measure petroleum and petroleum products. The test methods are incorporated by reference into the proposed rule and are available as specified in Section 98.6 of subpart A.

By incorporating voluntary consensus standards into this proposed rule, EPA is both meeting the requirements of the NTTAA and presenting multiple options and flexibility for measuring GHGs.

7.10 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this proposed rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment; it is a rule addressing information collection and reporting procedures.

SECTION 8
CONCLUSIONS AND IMPLICATIONS

In this RIA, EPA has examined the regulatory background, the development of the proposed mandatory GHG reporting rule, and estimated its costs and benefits. This section presents our overall conclusions.

8.1 Discussion of Results

EPA has developed this proposed rule in response to language contained in the FY 2008 Consolidated Appropriations amendment (December 26, 2007), which authorized funding for EPA to publish the rule on an accelerated schedule. The major market failure that the proposed rule is designed to address is one of inadequate or asymmetric information: while existing state and federal programs collect similar data, the resulting data are neither comprehensive nor consistent. As such, they are an inadequate basis for the formation or evaluation of future climate policy.

8.1.1 Development of the Proposed Rule

EPA examined several regulatory alternative scenarios that were developed by varying options across several program dimensions, including Threshold, Methodology, Frequency, and Verification. The proposed regulatory alternative calls for:

- a hybrid threshold, including a 25,000 tCO_2e threshold for all facilities except certain sectors where a capacity-based threshold is appropriate;
- a hybrid methodology, including facility-specific calculations for all facilities except those with CEMS monitoring in place under other programs;
- annual frequency except for those sources already reporting quarterly; and
- EPA as the verifier.

Other scenarios evaluated included the following:

1. A 1,000 tCO_2e threshold; recommended options for methodology, frequency, and verifier.
2. A 10,000 tCO_2e threshold; recommended options for methodology, frequency, and verifier.
3. A 100,000 tCO_2e threshold; recommended options for methodology, frequency, and verifier.
4. The measurement variable is changed to direct measurement; recommended option for threshold, frequency, and verifier.

5. The measurement variable is changed to default emissions factors; recommended option for threshold, frequency, and verifier.
6. Existing federal data used for measurement of fuel suppliers; recommended option for threshold, frequency, verifier, and methodology for other sources.
7. EPA uses default carbon content for fuel suppliers; recommended option for threshold, frequency, verifier, and methodology for other sources.
8. Reporting is quarterly; recommended option for threshold, methodology, and verifier.
9. Verification is done by a third party; recommended option for threshold, methodology, and frequency.
10. Reporting from upstream sources only; recommended option for methodology, frequency, and verifier.

8.1.2 Affected Source Categories

EPA considered both direct emitters of GHGs (stationary combustion sources, industrial processes, fugitive emissions, and biological processes); upstream emitters (fuel suppliers and industrial gas suppliers); and mobile sources. From these sources, EPA identified 18 source categories for which costs and impacts were examined.

8.2 Assessment of Costs and Benefits of the Proposed Mandatory GHG Reporting Rule

8.2.1 Estimated Costs and Impacts of the Mandatory GHG Reporting Program

Under the proposed rule, EPA estimates that 13,205 entities would be covered by the rule, emitting 3,870 $MtCO_2e$ per year. The total annualized costs incurred under the proposed rule by these entities would be $160 million for the first year and $127 million for subsequent years. Costs for general stationary combustion sources would be approximately $29 million in the first year and $24 million in subsequent years. Oil and natural gas systems would incur sector-wide costs of $33 million in the first year and $28 million per year in subsequent years. The Iron and Steel Production sector would incur $18 million in the first year and $14 million in subsequent years. The Landfills sector would incur $15 million in the first year and $10 million in subsequent years. The suppliers of coal and coal-based products sector would incur $11 million in the first year and $5 million in subsequent years. Pulp and Paper Manufacturing would incur sector-wide costs of approximately $9 million per year for both the first and subsequent years. Other sectors are all estimated to incur costs less than $9 million per year.

Overall, economic impacts on industry sectors are measured by comparing per-entity costs with average per entity receipts. These cost-to-sales ratios are less than 1% for establishments owned by small businesses that EPA considers most likely to be covered by the reporting program (e.g., establishments owned by a businesses with 20 or more employees) and small government entities. This analysis enables EPA to determine that the proposed rule will not have a significant economic impact on a substantial number of small entities. Overall, the proposed rule will impose national costs exceeding $100 million per year; the costs will be widely dispersed throughout the economy and relatively low on a per-entity basis. The estimated national costs represent approximately 0.001% of 2007 Gross Domestic Product. Thus, EPA does not estimate that there will be significant impacts on the economy in general or on individual sectors or small entities within those sectors.

8.2.2 Summary of Qualitative Benefits Assessment

EPA was unable to quantify the estimated benefits of the proposed rule. Instead, a qualitative assessment was performed, based on information from the literature and previous benefits assessments of existing emissions inventory programs.

Recent policy discussions have highlighted potential benefits to society of the GHG reporting program (Pew, 2008). Benefits to the public include building public confidence through clear and transparent emission measures and reports and the ability of the public to make facilities accountable for their emissions. Benefits to industry include the identification of GHG reduction opportunities and disclosure, which provides firms with incentives to reduce emissions voluntarily, and provides emissions data to service industries, such as insurance and financial markets. A GHG reporting system will also have the benefit of providing policy makers and analysts with a comparable data set that is comprehensive and reduces the potential for policy bias due to non-reporting by certain sectors. In addition, a mandatory reporting system is a key element to an overall GHG policy; no effort can succeed without it.

Studies published by OECD (2005) and EPA (2003) have documented benefits to various stakeholders, including the public, industry, investors, and government, of existing PRTRs. These benefits are likely similar to the benefits that would be experienced as a result of the proposed mandatory GHG reporting rule, and thus they provide a basis for a qualitative characterization of those benefits. The studies examined in Section 5 of this RIA describe the following types of benefits:

- Public
  - increased levels of trust towards government and industry where there are right-to-know laws concerning emissions;
  - information to enable citizens to negotiate directly with polluters; and
  - information to enable environmentally aware consumers to alter their consumption habits based on GHG emissions of producers.

- Industry
  - Public relations: having independent, verifiable data to present to the public would demonstrate appropriate environmental stewardship.
  - Standardization: uniform industry standards would reduce the cost of reporting relative to non-uniform, jurisdiction-specific, and allow facilities to benchmark their performance against other similar facilities.
  - Potential cost savings: mandatory monitoring may uncover previously unmeasured wasteful processes, yielding cost-saving conservation opportunities that would offset some of the costs of monitoring.
  - Potential customer data for service industries: information about GHG-emitting firms will be useful for firms that market emissions-reduction technologies, and to insurance companies for assessing risk.
- Investors
  - Information about emissions will enable investors to implement socially responsible investing using GHG emission information if they so choose.
- Government
  - Policy development: The greatest benefit to government of mandatory GHG reporting is the comprehensive, consistent data it would provide, enabling government to develop accurate, informed future GHG policy.
  - Comparability: A mandatory system would reduce the difficulties associated with comparing across different reporting standards across states or programs.
  - Compliance and policy evaluation: Publicly available nationwide data on GHG emissions will enable government to develop and robustly evaluate environmental policies, and to ensure compliance with the policies once implemented.

8.3 What Did We Learn through this Analysis?

EPA's examination of the costs and benefits of the proposed mandatory GHG reporting rule revealed that the proposed rule will impose an estimated $138 million (based on average costs over the first three years) in monitoring, recordkeeping, and reporting costs on generators of GHGs that are widely distributed throughout the U.S. economy. Impacts of the costs on individual sectors and entities are expected to be generally small, comprising less than 1% of entity receipts and approximately 0.001% of 2007 GDP. Thus, in spite of the overall national costs, macroeconomic impacts are not anticipated, and EPA does not believe that the proposed rule will impose significant economic impacts on a substantial number of small entities.

A review of the literature enabled us to characterize the expected types of benefits, which will be experienced by stakeholders, including the public, industry, investors, and government.

Based on this qualitative assessment and evidence from other existing programs, EPA expects the benefits of the proposed rule to be substantial.